MAINE PUBLIC UTILITIES COMMISION

FINAL REPORT

Pursuant to
"A Resolve to Direct the
Public Utilities Commission to Examine
Continued Participation by
Transmission and Distribution Utilities in this
State in the New England Regional
Transmission Organization"

Presented to the Utilities & Energy Committee

January 15, 2008

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EXECUTIVE SUMMARY

As this Final Report is submitted to the Legislature, Maine energy policy is once again at a crossroads. Citizens and policy makers are questioning the wisdom of Maine's electricity policy. Electric restructuring and is being reexamined. Regional institutions and market structures, keystones of Maine restructured markets, are the subject of particular scrutiny.

Concerns with the *status quo* regulatory structure in Maine are serious and valid:

- Electricity supply prices are rising, particularly in the Northeast: Since 1990 prices nationwide have increased by 35%, compared to 55% in Maine and New England – over two-thirds of the run-up has occurred since Maine restructured its electric supply industry;
- Electricity supply prices are volatile, aggravating price pressures: Due to New England's heavy dependence on natural gas, electricity prices expose consumers to the volatility of international fossil fuel markets – costing Maine consumers a substantial premium each year;
- Energy security is at risk: New England's dependence on natural gas poses a substantial risk to electrical reliability because of the region's remoteness from sources of natural gas, and weak natural gas transportation system;
- Maine consumers are paying more than their fair share of regional costs: Regional rules inequitably allocate costs among the region's consumers, driving the consumers of a smaller state like Maine to shoulder the costs of larger states;
- Decisions about Maine's electricity industry have moved to Washington: Through electric restructuring, wholesale power markets set electricity prices – elevating the influence of federal regulators over those of state institutions; and
- Consumers are left-out of the increasingly influential regional and federal decision-making process: Regional institutions do not have institutional mechanisms to ensure responsiveness to state goals.

Policy makers are sensing that the region is incapable of meeting consumers' needs for predictable and manageable electricity prices, and that regional institutions are not meeting environmental challenges.

- State Renewable Portfolio Standards (RPS) are not likely to be achieved within existing regional rules: Existing transmission cost-allocation rules inhibit the development of transmission to areas with abundant renewable resources, challenging the achievement of these important state environmental objectives; and
- Regional Greenhouse Gas Initiative (RGGI) objectives are not likely to be achieved: The New England States are leading the nation with the adoption of RGGI, which calls for 10% decrease in emissions of CO_2 from the power sector by 2018. However, the regional market is on a path to dramatically increase CO_2 emissions over this same period. Regional policies, including transmission cost allocation, inhibit the development of the non-CO_2 emitting resources necessary to meet RGGI goals.

In terms of price, reliability and environmental goals, the region must reduce the influence of fossil fuels on electricity production. New England currently relies on natural gas for more than 40% of its electricity production (compared to 20% nationwide), and natural gas plants set the market clearing price more than 68% of the time. In contrast, in 2006, renewable resources provided less than 10% of the region's electricity supply. In a recent Scenario Analysis, ISO New England, Inc. (ISO-NE) found that natural gas would continue to dominate the region's resource mix and determine future market prices and emissions levels under all plausible alternatives with the *status quo* regime.[1] Looking forward, 77% of the new resources in the planning queue are also natural gas-fired. This "business as usual" picture does not bode well for achieving electricity-related environmental, reliability and cost objectives of importance to the region. If these objectives are to be achieved, there must be changes to the *status quo* that encourage the development of renewable and other low-CO_2 resources.

In this Final Report, we describe necessary structural changes and present three options that would support the development of diverse, renewable and low CO_2 resources, and more reasonably treat Maine's interests within the applicable market and regulatory systems. Each option is, in our view, potentially better equipped to meet these goals than the *status quo*. The three options are:

A. The Market Reform Option

Maine would remain part of a reformed New England RTO and market. There are powerful synergies provided by the regional market. These include: a platform for retail competition; a regional approach to energy resource planning; sophisticated dispatch protocols and market systems that optimize generation efficiency; and a liquid market with many buyers and sellers.

The economies of scale provided by the size of the region allow it, through ISO-NE, to have access to a vast array of resources. Engineering, economic and regulatory professionals can be deployed to regional priorities in a manner that would be difficult to replicate in smaller systems. The regional system planning process and market system aid the region with its six political subdivisions to coordinate the electricity market and transmission system. In addition, ISO-NE has become a platform for regional policy development through vehicles like Scenario Analysis and various white papers periodically produced.

Nevertheless, the *status quo* will not achieve state and regional policy goals. Key reforms are necessary, and, if possible, likely to be achieved in two phases. In the near-term: (1) new transmission needed to access diverse resource generation in northern New England would be recognized as a reliability transmission upgrade; (2) market impacts that currently discourage development in resource states would be addressed; and (3) the New England States Committee on Electricity (NESCOE) would provide more robust public sector engagement with the RTO. In the longer-term: (1) transmission cost allocation would move toward a "beneficiaries pay" model; and (2) RTO governance and accountability would be

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[1] The ISO-NE Scenario Analysis, which is referenced throughout this Final Report, is available at http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/_mtrls/elec_report/scenario_analysis_final.pdf

addressed to ensure least cost solutions and state policy goals of importance to the region are pursued.

Because the Market Reform Option would build upon existing structures and agreements, it has the lowest transaction risk of the three options. Market Reform would also preserve retail competition in Maine, which is not certain with the other options, and would result in processes and decisions that could be synchronized with the region's policy and environmental goals. However, this option will be difficult to achieve. While the New England states have a history of leading on regional market issues of common interest, success is more varied when states' relative economic interests are impacted.

B. The Maine ITC Option

Maine transmission and distribution utilities would form an Independent Transmission Company (ITC) that would develop, maintain, and manage access to Maine's transmission system. In terms of supply for Maine consumers, a state-regulated load serving entity would be required, except, perhaps, for large industrial consumers. Supply sources would be "rate-based" or "cost-of service" rather than market-driven, and utilities could again construct, own and operate power plants.

The Maine ITC Option would allow Maine to have more control over the rules and structures that affect consumer costs, as well as over the types of electricity infrastructure sited here. With an ITC that would plan and operate transmission on a coordinated state-wide basis, this option would allow for cohesiveness and focus in terms of transmission development to meet Maine's goals and, potentially, the regional environmental objectives of RGGI. Rate-based generation could reduce price volatility. In terms of risks, the Maine ITC Option: (1) would be expensive and, perhaps, risky to start up; (2) could chill in-state investment of independent power production by disrupting the *status quo* and creating seams; (3) would inhibit retail competition; and (4) would expose consumers to stranded costs.[2]

C. The Maine/New Brunswick Option

Maine would join with New Brunswick and, possibly, other Maritime Canadian provinces. The framework for this option includes the following elements:

1. The New Brunswick System Operator (NBSO) would perform joint dispatch of the bulk power system for the region;

2. Transmission systems would be jointly planned;

3. There would be a common energy market relying on a hub located in New Brunswick; and

[2] Of course, this was a key driver of restructuring in the first place.

4. A state-regulated entity would supply Maine consumers.[3]

For this option to be viable for Maine and New Brunswick, key reforms to the existing systems in New Brunswick should be considered. To attract the private investment needed for development of new renewable capacity, market rules must ensure transparency, fairness, consistency and continuity. A common market for Maine and New Brunswick must allow for: (1) system-wide security constrained economic dispatch; (2) system-wide open access transmission; (3) an independent system operator free of control of any single government or market participant; and (4) enhanced access to the New England market. In addition, the vast majority of New Brunswick resources are currently concentrated in the hands of New Brunswick Power, which creates a potential market power problem. Although it may be possible to develop market mitigation strategies, at present, it is not clear whether consensus could develop around such strategies or whether they would be workable. Finally, this option may have large transaction costs similar to the Maine ITC Option and would require the cooperation of the transmission and distribution utilities.

The Maine/New Brunswick Option would allow the consolidated region to develop and transmit diverse resources in a coordinated way. This option would also allow Maine to remain part of a larger market, but one in which Maine would be a more prominent player and, thereby, could better protect consumer and State interests. As with the Maine ITC Option, the Maine/New Brunswick Option would involve new structures and agreements, and is therefore a risky and potentially costly venture. This option, like the Maine ITC Option, could also inhibit retail competition.

I. OVERVIEW

A. Background

On April 13, 2006, Governor John E. Baldacci signed a "Resolve, To Direct the Public Utilities Commission to Examine Continued Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization" (Resolve).[4] The Resolve directs the Maine Public Utilities Commission (Commission) to undertake an inquiry in order to:

> (1) determine the legal options for directing Maine Transmission and Distribution Companies that are currently part of the New England Regional Transmission Organization (RTO) to withdraw from the RTO;
>
> (2) determine the costs and benefits of directing these utilities to withdraw from the New England RTO; and

[3] As with Option 2, the need for this load serving entity could be limited to loads that could not access a liquid, functioning competitive market.
[4] Resolves 2005, ch. 187

(3) examine the other reasonable options for providing the services currently provided by the New England RTO, including any options involving Canadian governments, agencies or other authorities as well as options involving other state governments or agencies within the United States.

The Resolve required the Commission to submit two reports the Legislature: an Interim Report in January 2007 and a Final Report by January 1, 2008. On January 16, 2007, the Commission submitted the Interim Report on the status of the inquiry and set forth the following preliminary findings:[5]

A. Significant inequities exist in the Regional Transmission Organization's[6] transmission cost allocation system and the pricing of generation services.

B. There are no insurmountable legal, economic or technical barriers to Central Maine Power Company (CMP) and Bangor Hydro-Electric (BHE) withdrawing from the ISO-NE regime. However, the State of Maine is limited in its ability to direct such a withdrawal over the objections of the utilities, and any such withdrawal would be subject to approval by the Federal Energy Regulatory Commission (FERC).

C. There are reasonable alternatives to continued participation in the RTO. These include the formation of one or more Maine independent transmission companies, and the development of a common Maine/Canadian Maritimes market.

Since the Interim Report was submitted, the Commission continued its exploration of alternatives to the RTO *status quo* in conjunction with the February 8, 2007 Memorandum of Understanding (MOU)[7] between the Governor of the State of Maine and the Premier of the Province of New Brunswick by which the governments of Maine and New Brunswick agreed to explore opportunities for mutual benefits from their electrical interconnection. As highlighted in the MOU Phase I Report, [8] the governments of Maine and New Brunswick see opportunities based on their geographical and electrical positions, particularly with respect to developing sources of, and a corridor for, clean, renewable power, and have committed to explore ways to realize these opportunities.

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[5] The Interim Report is available at http://www.maine.gov/mpuc/staying_informed/legislative/2006legislation/ISO-NEInterimReport.doc

[6] ISO-NE is the RTO for New England.

[7] The MOU is available at http://www.maine.gov/tools/whatsnew/index.php?topic=Gov+News&id=29687&v=Article-2006

[8] The MOU Phase I Report is available through the Commission's on-line case file at http://mpuc.informe.org/easyfile/easyweb.phpfunc=easyweb_query , Reference Docket 2006-364.

B. Findings

Since the Interim Report was submitted, it has become increasingly evident that, in the context of considering options within regional wholesale power markets and RTOs, significant issues emerge by virtue of the growing demand in New England for renewable and low carbon sources of energy and Maine's potential as a resource and transport corridor to meet this demand. In this Final Report, we present our analysis within this context and recommend that any future course of action, including any RTO or market change or alternative, be measured by: (1) how effectively it enhances opportunities for the development and transport of renewable resources; and (2) how well it addresses problems with the *status quo*, most notably high electricity costs and inequitable or deficient RTO and market rules and structures.[9]

The New England RTO and wholesale market in their current forms expose Maine consumers to high and, in some cases, inequitable costs, and a resource mix dominated by natural gas and other fossil fuels. In addition, the existing regime may hinder our ability as a region to meet environmental policy objectives such as the CO_2 caps set by the Regional Greenhouse Gas Initiative (RGGI). Although these problems are not attributable to a market regime *per se*, they may not be resolvable within the particular institutional and regulatory structures that exist today.

This report presents three possible paths to address problems with the *status quo*. These paths are: (1) market reforms within ISO-NE; (2) an independent Maine ITC; and (3) a newly formed Maine/Canadian system. As described in Section V, each of the three alternatives has risks and benefits, and achieving the necessary changes will require significant commitment by the Governor, the Legislature, the Office of the Public Advocate and the Commission, regardless of which framework is pursued.

The Commission respectfully submits this Final Report to the Legislature. We believe that each of the three options presented in Section V would result in better outcomes for consumers than the *status quo*.

[9] The Report was released in draft form for comment on December 4, 2007, and this Final Report reflects several points made by commenters. In general, the comments reflected a preference that Maine remain within the ISO-NE market rather than separate and create a new market system. The comments may be reviewed in their entirety at http://mpuc.informe.org/easyfile/easyweb.phpfunc=easyweb_query, reference Docket No. 2006-364.

II. THE *STATUS QUO* WILL NOT ACHIEVE KEY POLICY GOALS

As 2008 begins, Maine's electricity policy is again at a crossroads. Ten years ago, Maine adopted laws that restructured the electricity industry, one effect of which was to place greater reliance on the regional wholesale electricity market. [10] The move to markets followed a policy embraced by Maine that supported long-term contracts with renewable power producers. Both policies moved away from the traditional model in which generation was owned and operated by the regulated utility and the PUC made rate determinations and regulated the investments of the utilities. Each regulatory change was, in turn, a reaction to a prior policy that was deemed no longer desirable.[11]

Maine consumers now acquire their electricity supply from a regional wholesale power market rather than utility-owned power plants, and rely upon the ISO-NE as the primary agent to administer this market. ISO-NE also manages and dispatches the transmission system, is responsible for the reliability of the electricity system and takes the lead on transmission system planning.[12] Moreover, ISO-NE is increasingly taking on the role of a regional think-tank for energy policy, as evidenced by the recently released Scenario Analysis. [13]

ISO-NE has evolved from a transmission system operations functionary subordinate to the region's utilities to a $100 million per-year enterprise. ISO-NE has authority over the region's transmission utilities operations, independent legal standing at the Federal Energy Regulatory Commission, and an independent board of directors.[14] While the breadth of ISO-NE's activities today exceeds many expectations, its fundamental activities were envisioned by policy makers at the dawn of the region's experiment with restructuring.

The wholesale market structure and transmission system that exist today is the model that the Commission determined was the most advantageous for consumers in 1996. The Commission determined that an independent system operator with broad transmission and reliability responsibilities, and a wholesale power market, also with independent oversight, are foundational elements of retail electricity market restructuring.[15] The Commission opined that: Maine cannot resolve all issues that will determine whether retail competition will succeed. Some issues *must* be addressed on a regional level or before the Federal Energy Regulatory Commission.[16] The Commission believed in 1996, and continues to believe today, that retail electricity markets are dependent upon a functional wholesale power market. In requesting that the PUC study possible alternatives to ISO-NE, the Legislature, in effect, is asking whether the performance of the restructured market, in general, and the ISO-NE framework, in particular, have been successful. The Legislature is also asking whether Maine would be well advised to continue on this course for the foreseeable future. These questions are important, and the

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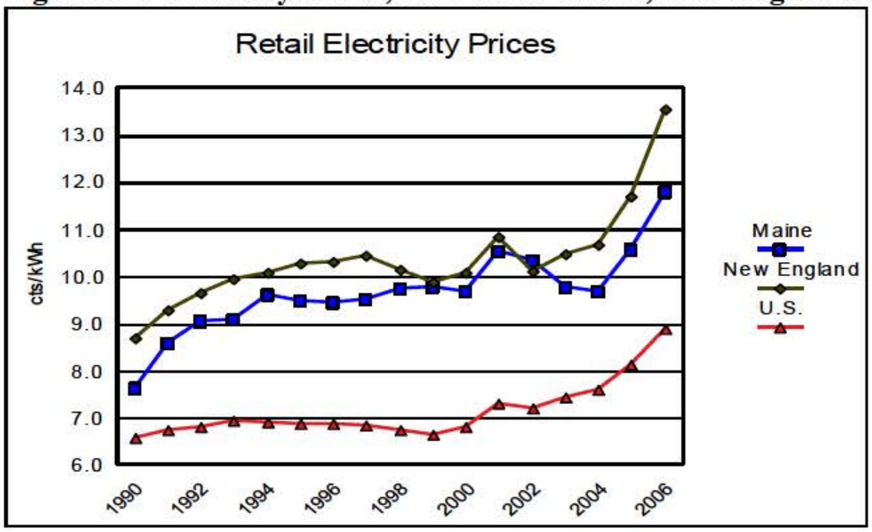
[10] Most other New England states adopted similar laws at or about the same time.
[11] The Legislature is now considering moving away from markets and has asked the Commission to study the re-integration of utilities in the construction and ownership of electric power generation. Resolves 2007, Ch 54.
[12] See, e.g. the ISO-NE 2006 Annual Markets Report.
[13] Scenario Analysis can be found at http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf
[14] See http://www.iso-ne.com/regulatory/hst_legal/index.html
[15] See, Electric Utility Industry Restructuring Report and Recommended Plans, December 31, 1996, pp 115-124
[16] *Id*. at 115. (emphasis added).

analysis is complex and broad in scope. Although restructuring may have advantages in some important respects, for example, by insulating consumers from the risks of investments in power plants, thereby avoiding another round of stranded costs, the existing regime is disadvantageous in several ways:

A. High and Volatile Energy Prices will Continue to Pressure New England

Over the past several years, electricity costs in Maine, as well as throughout New England and the U.S. generally, have increased dramatically. Since 1990, prices nationwide have increased by about 35%, and in Maine and New England the increase has been about 55%.[17] The most dramatic increases over this period have occurred since 2000.

Figure 1 – Electricity Prices, 1990-2006: Maine, New England and U.S.



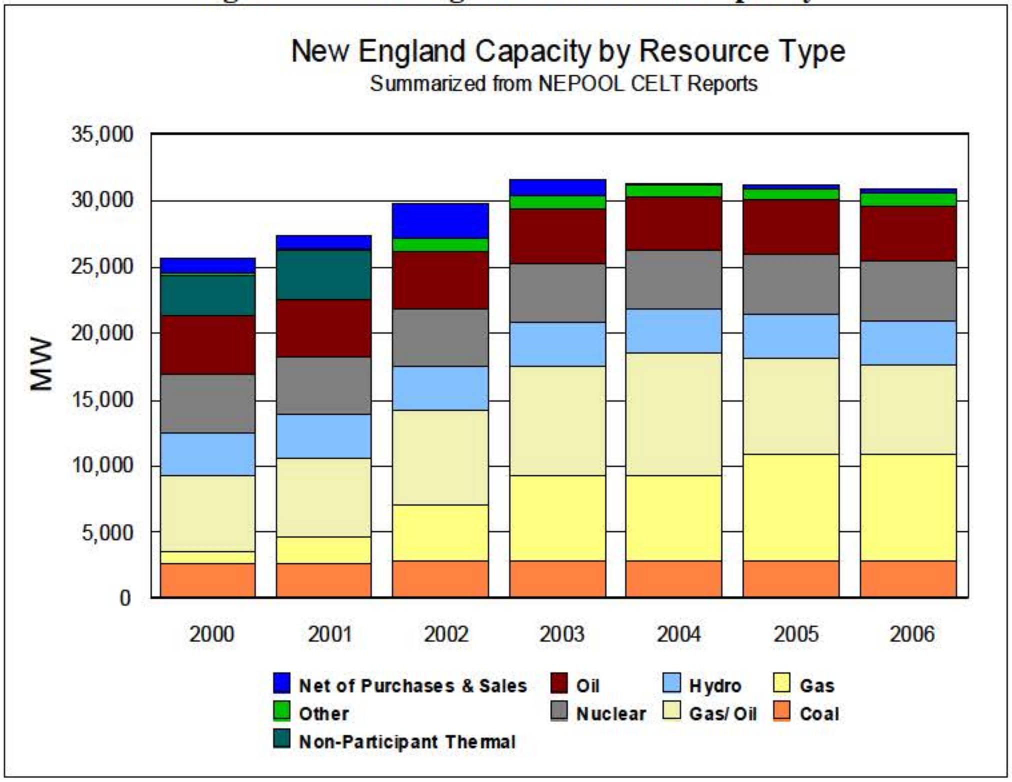
These increases, particularly in New England, have been driven by wholesale electricity supply costs, which in turn have been driven by fossil fuel prices, most notably natural gas. [18] Natural gas use has increased from a fraction of the fuel used in the region ten years ago, and now dominates our electricity production, in recent years comprising more than 40% of total regional production capacity, compared to 20% nationwide.[19]

[17] Source of data – Energy Information Administration

[18] High energy costs are not new to the Northeast. A 1970 report of the New England Governors found that "electric power is neither abundant nor inexpensive" here. At that time, the Governors attributed a large part of the region's high electricity costs to the "remoteness of New England from sources of coal." Since then the region has weathered several energy crises. Each crisis forced major policy changes ranging from a regional commitment to nuclear power to the restructuring of our electric utility industry.

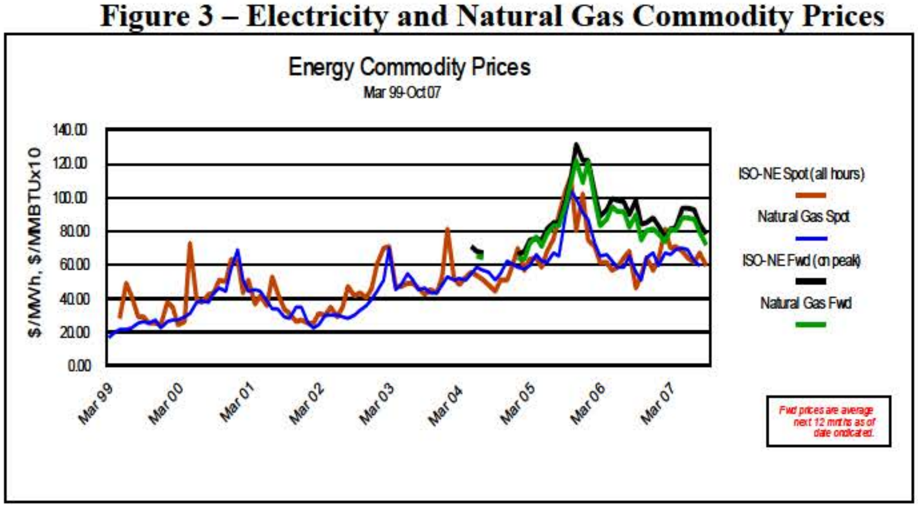
[19] ISO-NE 2006 Annual Markets Report

Figure 2 – New England Generation Capacity



As is evident from Figure 3 below, New England electricity prices move in lock-step with natural gas. This is not surprising, given the role that fuel plays in the New England market. Market prices in ISO-NE are set by the generator at the top of the bid stack, which is a natural gas plant 68% of the time; thus, the effect of natural gas on electricity prices is amplified.[20]

Figure 3 – Electricity and Natural Gas Commodity Prices

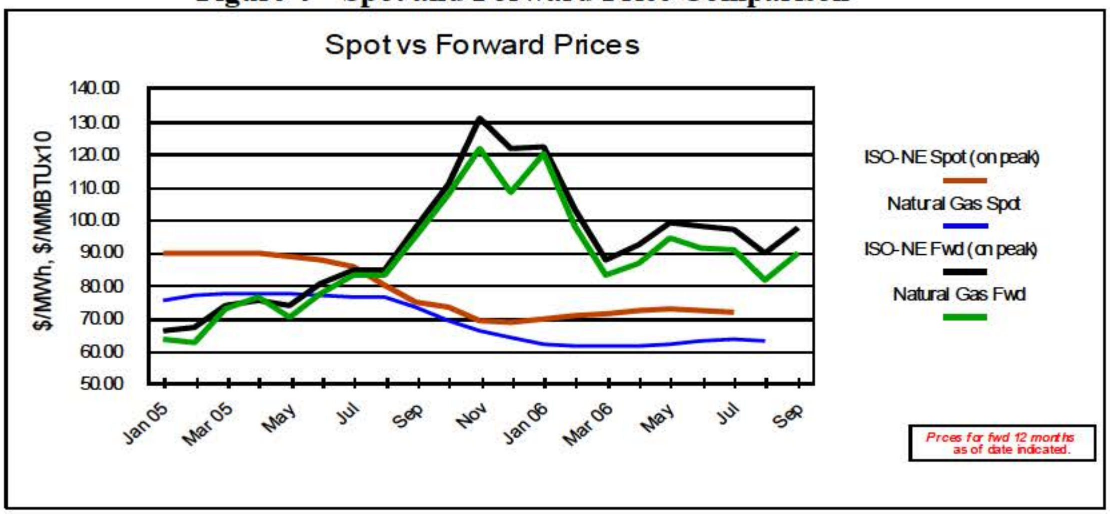


[20] There is a uniform clearing price (UCP) in the ISO-NE market. In other words, all resources are paid the price of the marginal unit bid (the most expensive generator needed to clear the load demand for the relevant period).

New England's electricity markets are also volatile. Natural gas, in addition to being a costly fuel, is vulnerable to supply risk. Globally, the countries where natural gas and oil is sourced are often subject to political tumult. Extreme weather events like Hurricane Katrina have also disrupted natural gas supplies, sending prices soaring. This volatility is passed on to retail electricity customers. While some customers have grown accustomed to the volatility, after Hurricane Katrina at least one major Maine business approached the Commission for regulatory relief to shield it from electricity market volatility to enable it to continue as a going concern.

In recent periods the forward markets have imputed a premium in prices to account for the supply risk. This premium is evident in the tendency of the forward markets for natural gas and electricity to be more expensive than spot markets. As Figure 4 demonstrates, the premium is particularly pronounced in the wake of extreme events such as Hurricanes Katrina and Rita.

Figure 4 – Spot and Forward Price Comparison



Recent data indicates a premium, on average, in the range of $15/MWh in forward prices related to supply risks. In other words, the markets for natural gas and electricity, anticipating a potential political event or weather disruption, are reflecting these risks which are then passed on to consumers in the form of higher prices. The resulting cost to Maine consumers based on the recent average premium is in the range of $150 million per year. However, as shown in Figure 4, at some points the premium has been much larger. The premium has also been negative, although that has not been the case for more than two-and-a-half years.[21]

In addition to fuel-driven energy cost increases, polices pursued within the region have increased other components of electricity costs. The forward capacity market settlement will add as much as 10% to customers' bills by 2010. Socialization of transmission investment,

[21] Because of the uniform clearing price, the volatility affects the price of all MWhs in the market, even though natural gas represents only 40% of the MWhs produced.

among other things, will increase electricity bills in Maine by about $500 million over the next five years.[22]

B. Natural Gas Dependency Affects Reliability

New England's dependence on natural gas also affects reliability. In 2004 and 2005, ISO-NE noted potential electricity reliability problems with the region's dependence on natural gas for electricity generation, particularly in the winter.[23] In 2004, a sustained cold snap in New England caused a generation capacity shortage, bringing the region to the brink of rolling blackouts.[24] In 2005, following Hurricanes Katrina and Rita, natural gas supplies into the Northeast were significantly reduced; however, because that winter was unusually mild, there were no power system disruptions. In early December, 2007, a natural gas supply disruption on Sable Island disrupted natural gas flows into the region, causing a New England-wide capacity deficiency. ISO-NE has opined that the reliability risk associated with natural gas can be mitigated by the siting of LNG facilities in the region, and by greater fuel diversity.[25] However, regional transmission cost allocation policies do not appear geared to facilitating the development of new diverse generation resources.

C. The Regional Market System is Challenged to Meet Environmental Priorities

Carbon dioxide emitted by fossil fuel power plants is a leading contributor to global warming.[26] Since the mid-1990s, more than 10,000 MW of natural gas generation has been added in New England, and, in a key finding by the ISO-NE in its Scenario Analysis, natural gas will continue to dominate the regional supply mix and emissions profile.

The fleet of generators currently proposed for interconnection with the region's transmission system (in the "interconnection queue") demonstrates what the current market system offers to meet the increasing demand for electricity. As shown in Figures 5 and 6, the resources in the interconnection queue as of September 2006 were 77% gas-fired. Thus, the *status quo* will deliver natural gas as the predominant fuel source for new generation facilities at least into 2012.

[22] *See* Appendix A, Table 5.
[23] See 2004 and 2005 ISO-NE Annual Markets Reports
[24] See 2004 ISO-NE Annual Markets Report and Final Cold Snap Report, October 12, 2004.
[25] Scenario Planning, at 61.
[26] See, e.g., EIA report at http://www.eia.doe.gov/oiaf/1605/flash/flash.html.

Figure 5 – Generator Queue Projects by Fuel Type

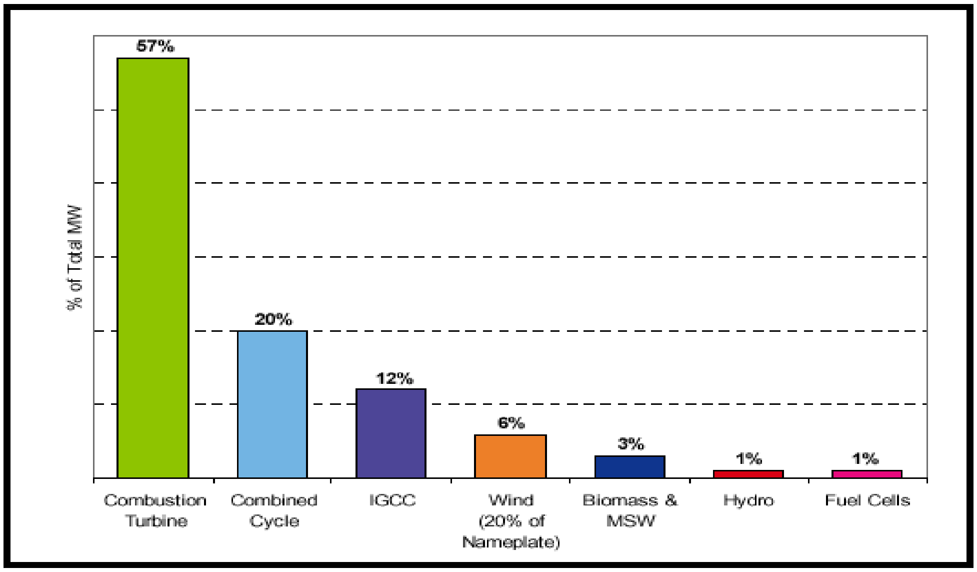


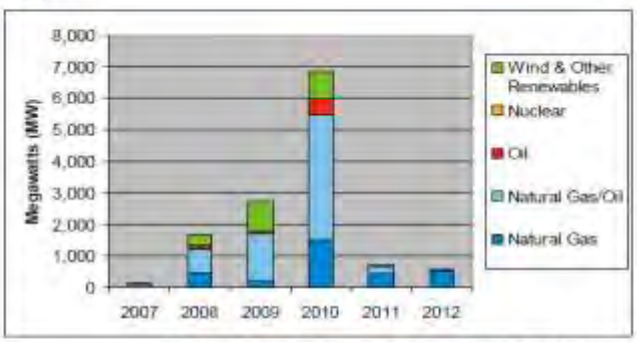
Figure 2-2: The mix of fuels for proposed power plants in the ISO's Generator Interconnection Queue as of September 30, 2006.

Note: All of the technologies are assumed to be at 100% of their nameplate capacity, except for wind, which is assumed to be at 20% of its nameplate capacity.

Source: ISO-NE Scenario Analysis at p. 18.

Figure 6 –Generator Queue Projects by Fuel Type and Year

Actual and Projected Annual Capacity Additions
By Fuel Type



	2007	2008	2009	2010	2011	2012	Total	% of Total
Wind & Other Renewables	9	361	921	880	43	43	2,257	17.8
Nuclear	0	70	0	0	0	0	70	0.6
Oil	0	54	78	491	0	0	623	4.9
Natural Gas/Oil	89	736	1,512	3,972	244	0	6,553	51.8
Natural Gas	13	479	204	1,507	411	543	3,157	24.9
Totals	111	1,700	2,715	6,850	698	586	12,660	100.0

Note: To date, approximately 100 MW of new generation has gone into service in 2007. An additional 15 MW is projected to be in commercial operation by the end of the year.

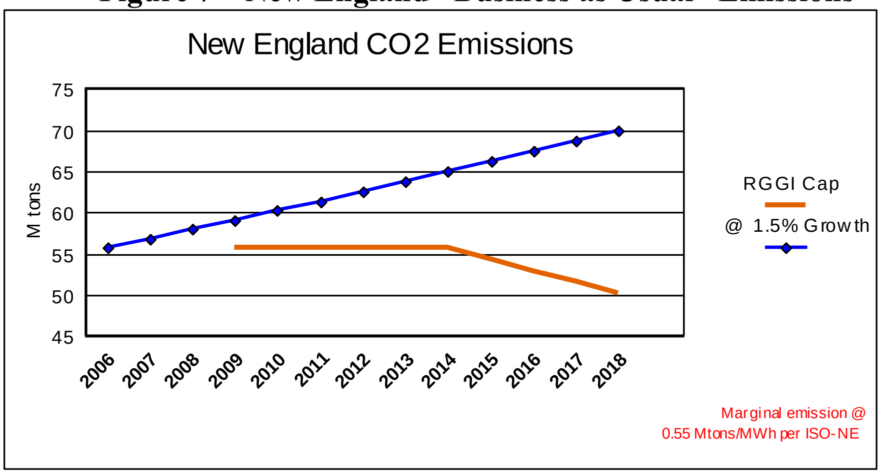
Source: ISO-New England – Forward Capacity Market (FCM)/Generation Interconnection Workgroup Presentation, October 25, 2007.

1. <u>"Business as usual" generation development will not support RGGI's climate change mitigation goals.</u>

In order to combat climate change, several northeastern states have adopted the Regional Greenhouse Gas Initiative, or RGGI.[27] RGGI is a cap-and-trade program for CO_2 emissions, and is similar to the programs for SO_2 and NO_X reductions that have been in place for over a decade. RGGI will cap CO_2 emissions from power plants at current levels in 2009 and then ratchet emissions down by 10% beginning in 2015.

However, the expected future path of CO_2 emissions under the "business as usual" scenario diverges markedly from RGGI goals. With electricity demand increasing at an average annual rate in the range of 1.5% and the regional outlook for natural gas generation described above, CO_2 emissions in New England would *increase* by 15 million tons per year by 2018, a jump of more than 25%, and exceed the RGGI cap by 40%.[28]

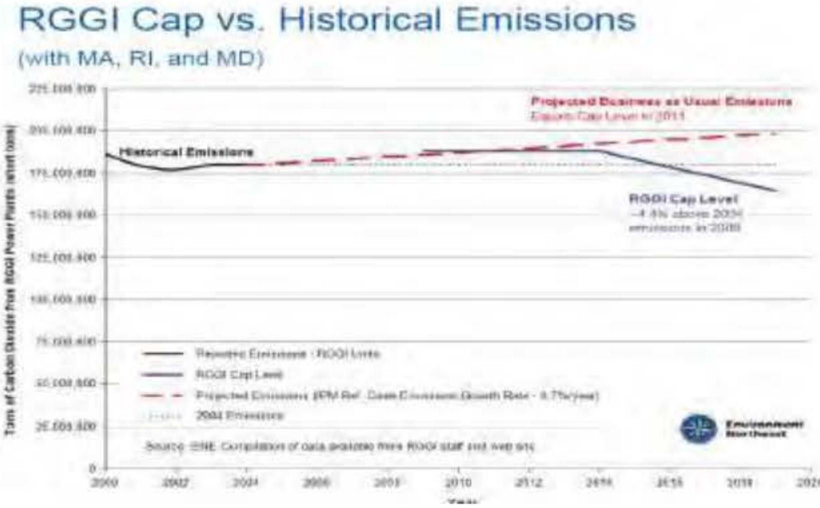
Figure 7 – New England "Business as Usual" Emissions



Recent work done by Environment Northeast, a leading regional climate change advocacy non-profit, indicates similar results for the full RGGI region.

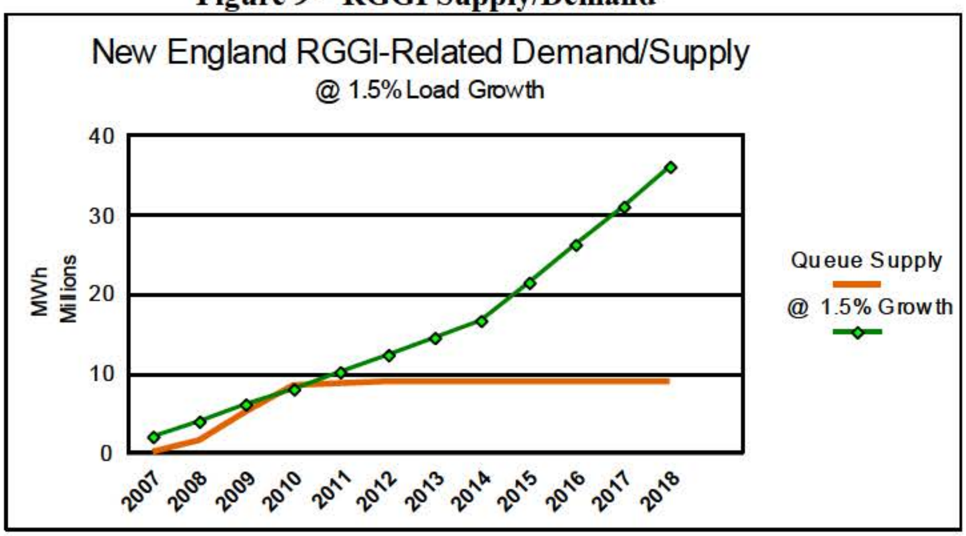
[27] All states in New England, plus New York, New Jersey, Delaware, Maryland, D.C.
[28] If demand growth is lower than 1.5%, then increases in CO_2 would also be lower, all else equal.

Figure 8 – RGGI Region Emissions



It is clear that using energy more efficiently is an essential component of combating climate change, as it necessarily decreases the need to burn fossil fuel to produce energy. RGGI will promote energy efficiency as a key tool to meeting CO_2 reduction goals by targeting revenue from allowance sales toward consumer efficiency measures. However, the development of new resources, particularly renewable and low carbon resources, is also critical to meet growing demand and the RGGI caps. As load grows and CO_2 emissions caps ratchet down, RGGI-related demand in New England for carbon-free power will exceed 30 million MWh per year by 2018, the equivalent of more than 4,000 MW of biomass or 9,800 MW of wind capacity.[29] As noted above, ISO-NE's Scenario Analysis indicates that under no circumstances can New England's *status quo* case meet RGGI's goals.

Figure 9 – RGGI Supply/Demand



[29] Based on capacity factors for biomass and wind of 85% and 35%, respectively .

2. *Status quo* generation development will not support RPS requirements.

All states in New England have Renewable Portfolio Standards (RPS) requiring specified amounts of renewable supply; in most states these requirements increase over time.[30] The New England RPSs are summarized below:

Figure 10 – New England Renewable Portfolio Standards

Massachusetts
2.5% new renewables in 2006, increasing to 5% in 2010

Connecticut
4% Class I and Class II resources by 1/1/2004, rising to 10% by 1/1/2010;
4% Class III resources by 1/1/2010

Rhode Island
16% by 2020

Vermont
Total incremental energy growth between 2005-2012
to be met with new renewables (10% cap)

Maine
30% from renewable and efficient resources.
New renewables ->> 10% by 2017

New Hampshire
25% by 2025

As load grows and RPSs require supply mixes that include increasingly higher proportions of renewable energy, demand for compliant renewable power[31] will increase and likely exceed available supply.[32] In the aggregate, the RPSs will require from 13-to-14 million MWh of renewable energy per year by 2015, roughly equivalent to 1,800 MW of biomass or 4,400 MW of wind capacity.[33]

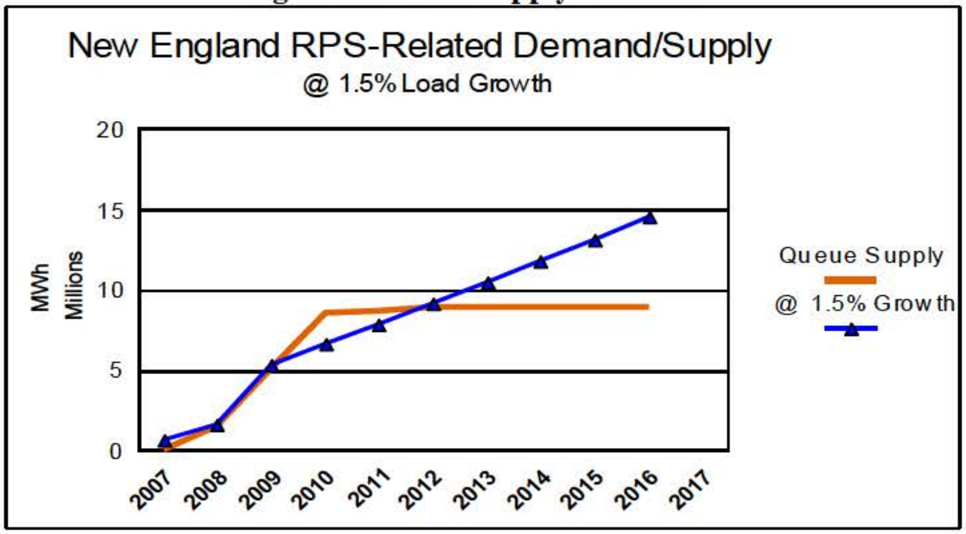
[30] RPSs provide a subsidy for desired generation types. As such, they affect market outcomes in terms of new resource development. Depending upon the size of the subsidy, the effect of an RPS can be dramatic. Indeed, over 1,000 MW of new wind generation planned for development in Maine is reliant, at least in part, on the subsidies provided by virtue of the RPSs in Massachusetts and Connecticut.

[31] Indeed, shortfalls may already exist. In 2004 and 2005, Massachusetts met about one-third of its RPS with alternative compliance mechanism payments (ACPs) instead of supply-backed renewable energy credits (RECs). In 2005 alone, ACPs were in the range of $20 million.

[32] Because of the strong correlation between RPS funds generated by the ACPs, i.e. money paid to cover RPS shortfalls, and the demand for new resources, ACP funds could be considered as a potential source of financial support for new transmission needed to import remote resources. The ACP amounts are potentially very large. Given ISO's estimate that RPS-related shortfalls are in the range of 6% the region's load by 2015, this translates to more than $500 million per year.

[33] *See* FN 28.

Figure 11 – RPS Supply/Demand



3. New England cannot meet its policy objectives with the *status quo* regulatory regime.

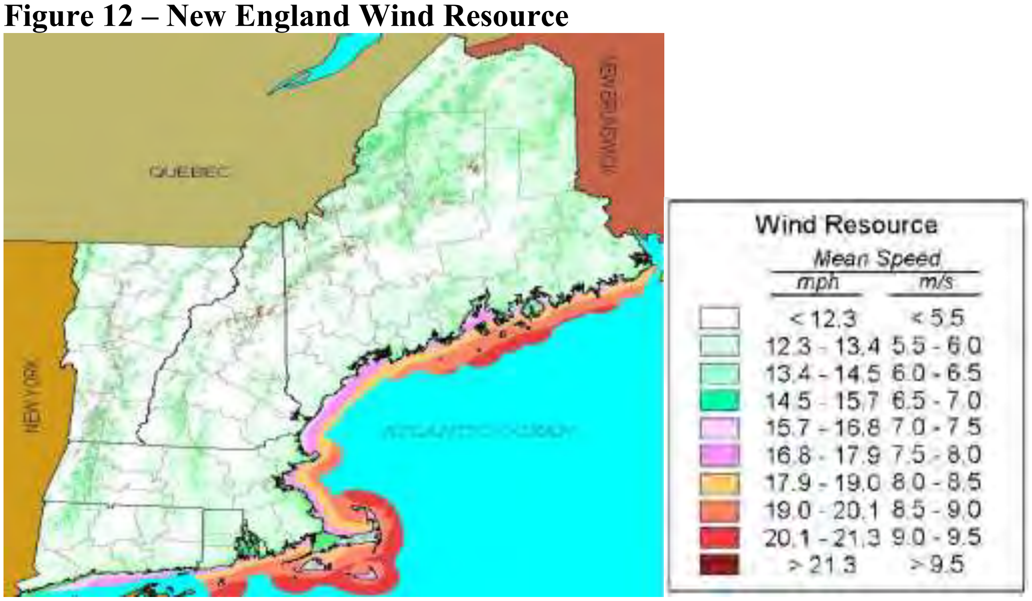
Figures 9 and 11 illustrate the pronounced divergence in the region between stated policy and environmental goals and current and expected resource development. Without a change in direction, the costs, volatility, supply vulnerability and emissions to which the region is exposed because of its dependence on natural gas will not improve and, indeed, may worsen under the *status quo* regulatory, institutional and market systems.

III. MAINE'S ROLE

Maine is at once affected by the same pressures as the region, but also in a unique position to help solve the region's problems and, in so doing, create opportunity for the State. As noted above, in its Scenario Analysis ISO-NE found that, absent policy change, natural gas generation would continue to be the resource of choice in the region.[34] The ISO found that, in addition to energy efficiency, imported renewable energy from Canada could help the region reduce its reliance on natural gas and meet its climate change goals. But meeting New England's growing demand for electricity with these resources will require several thousand MWs of new resources and associated transmission to be developed in order to serve loads in population centers like Boston. (See Section II). Maine's abundance of resources and proximity to the Canadian resource base present a unique opportunity in this regard. Unlike much of New England, where it is becoming more difficult and expensive to site new facilities, and where the availability of certain types of renewable resources, e.g. hydro, is particularly limited, Maine appears well-positioned for new resource development to supply these markets due to its regional advantages in terms of; (1) resource availability, (2) siting, and (3) cost. Moreover, because of Maine's strategic geographic position, it is also well-positioned to serve as a transport corridor to allow a potentially vast supply of clean power to flow from Eastern Canada to New England.

Maine currently has the largest operating wind plant in the region, and several more wind projects comprising over 1,000 MW of generation are on the drawing board. Thousands of additional megawatts could be available from Maine according to materials presented to the Maine Wind Power Task Force.[35] As shown in Figure 12, the best wind resources in the region, shown in red and burgundy, tend to be offshore and in the mountainous areas of Maine, Vermont and New Hampshire.[36]

Figure 12 – New England Wind Resource



[34] Scenario Analysis, p 8.
[35] Based on October 30, 2007 presentation by Sustainable Energy Advantage, LLC to the Task Force.
[36] Source: TrueWind Solutions, http://truewind.teamcamelot.com/ne/

Maine is also strategically located adjacent to the sources of energy in Eastern Canada that are necessary to meet the region's climate change goals. The MOU Phase I Report identified the potential for several thousand MW of new non-CO_2 of low-CO_2 emitting generation resources from Maine and Atlantic Canada. Figure 13 provides a summary of these resources:[37, 38]

Figure 13 – Potential Capacity in ME and Atlantic Canada

		Capacity Nameplate MW
New Brunswick		
Wind	Province-wide	1,500
Biomass	Province-wide (up to)	400
Nuclear	Pt. Lepreau	1,000
Nova Scotia and PEI		
Wind	Total	800
Newfoundland and Labrador		
Hydro	Lower Churchill	2,800
Hydro	Other locations	2,000
Wind	Lower Churchill (approximate)	1,500
Bay of Fundy		
Tidal	Estimate of potential	400
Maine		
Wind	Kibby Range, Western Maine	132
Wind	Black Nubble, Western Maine	54
Wind	Stetson, Eastern Maine	57
Wind	Aroostook County	950
Total Nameplate		**11,593**
Total Derated (wind derated to 30% of nameplate)		**8,098**

How to access and develop these resources for the region in an equitable manner is a compelling question for Maine and our neighbors. The Commission believes that the impact of policies to combat climate change, the need for fuel diversity of electricity supply, and siting challenges will be the greatest obstacles for the regional market system, and that the *status quo* is not up to the task of meeting these challenges.

[37] Source: New Brunswick/Maine MOU; Phase 1 Report. June, 2007.

[38] BHE noted in its December 21, 2007 Comments that an estimated 2,000 MW of new renewable generation may also be available from Quebec, and that other types of renewable resources may be available in Maine.

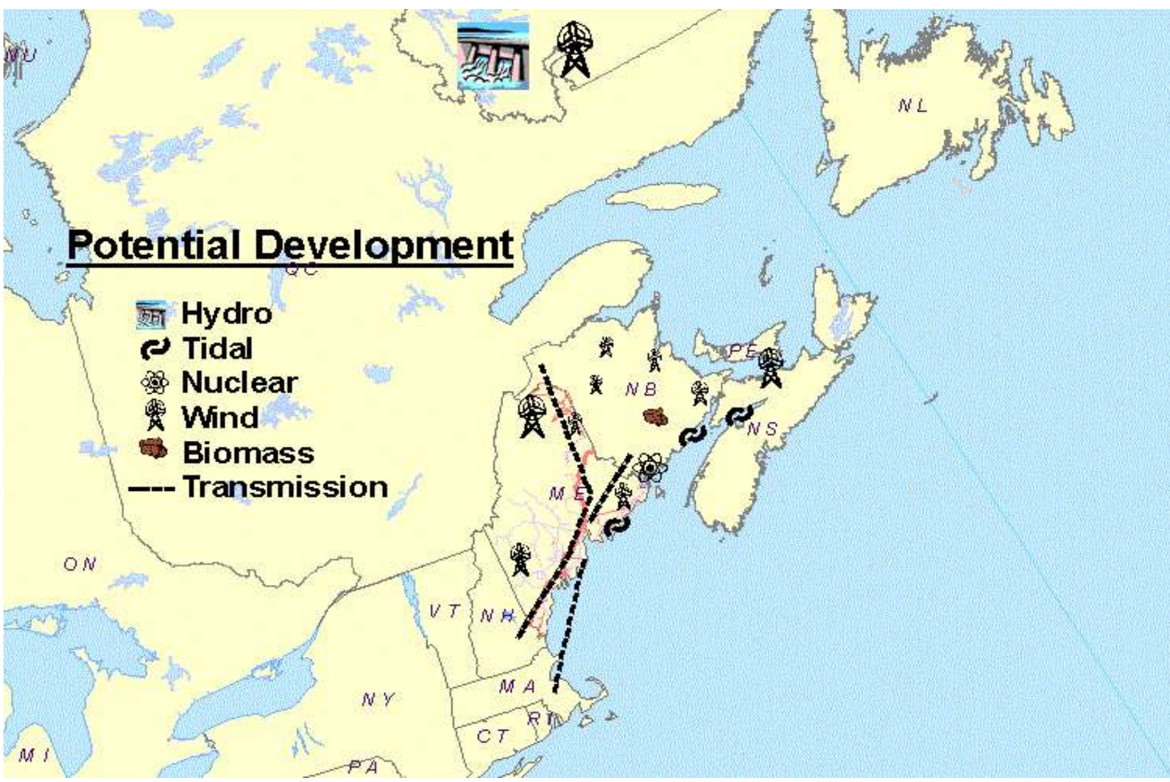
IV. *STATUS QUO* REGIME INHIBITS SOLUTIONS

New England's regional market structure is not equipped to address the challenges before it, or to solve those challenges with the resources in northern New England and Eastern Canada. New England must build substantial transmission to access these remote renewable resources. However, it is unclear whether the existing regional rules and structures can efficiently and effectively develop and fund this transmission. There is no formal coordination between transmission and generation needs, and the costs of new transmission investment are not recovered in either an efficient or equitable way. In addition, ISO-NE does not have incentives to pursue least cost alternatives and ISO-NE governance lacks sufficient input from regional leaders in solving the region's problems.

A. Extensive Transmission is Under Consideration in Maine – Coordination with Need is Lacking

Serving growing demand in New England and realizing the above-described resource development opportunities in Maine and Atlantic Canada cannot be achieved without sufficient transmission between the regions, much of which could be sited in Maine.

Figure 14 - Location of Resource Supply and Demand [39, 40]



[39] Source: New Brunswick/Maine MOU Phase 1 Report.
[40] In its December 21, 2007 comments, BHE noted that its recently announced Northeast Energy Link (NEL) project would provide additional transmission from Orrington to the south.

Although there are major transmission projects underway or under consideration in the region that would enhance transfer and export capability to some degree, these projects may be hobbled by irrational rate design and insufficient planning. By year-end 2007, the Northeast Reliability Interconnect - International Power Line (NRI-IPL) project will be completed and on-line. This project involves a second 345 kV transmission line between New Brunswick and Orrington, Maine, and will increase transfer capability from New Brunswick to Maine to 1,000 MW.[41] Other transmission projects in Maine are under consideration. The Maine Power Reliability Project (MPRP) involves a proposed broad scale build out of new transmission in the CMP service area, including project components to improve the reliability of particular areas in the CMP system and to upgrade the 345 kV backbone. The MPRP potentially includes additional 345 kV circuits from Orrington to the greater Portland area and on to the Maine-New Hampshire interface, potentially increasing the capacity to export power to southern New England.

Also under consideration is a transmission project that would interconnect the Maine Public Service (MPS) system directly to the rest of the Maine and New England transmission grid.[42] (The Maine Power Connection, or MPC.) In addition to providing additional transfer capability between Maine and New Brunswick, the MPC could provide a more direct path for sales to New England from generation resources in northern Maine[43] and Canada.[44] In their December 21, 2007 comments, CMP and BHE both noted recently announced transmission project proposals: (1) the proposed Northeast Energy Link (NEL) project, to be developed by BHE and its parent, Emera, consisting of a high voltage D.C. line that would increase transfer capability between New Brunswick and New England; and (2) the Maine-Canada Renewable Highway, described by CMP as transmission to match available renewable resources. Finally, other developers have proposed overland and undersea transmission cables from Maine to Massachusetts – each designed to increase export capability into southern New England.

As these projects and others in the region are being considered, however, there is no overarching and comprehensive process to ensure that the transmission actually needed by the region is developed. Although ISO-NE is intended to serve this function to some extent, as described in the following sections of this report, the *status quo* is not equipped to yield solutions that are least cost, efficient, equitable, or promote state and regional policy and environmental goals. Finally, the *status quo* does not adequately consider transmission needs in the context of generation resource adequacy or diversity goals.

B. New England's Method of Transmission Cost Allocation Creates Irrational Economic Outcomes and Inhibits Access to Remote Generation.

[41] The transfer capability from south to north will increase to 500 MW.

[42] Currently, MPS is directly connected only to the New Brunswick system and interchanges between MPS and the rest of Maine and New England must be transmitted across the New Brunswick system.

[43] Northern Maine includes MPS as well as three consumer-owned utilities: Eastern Maine Electric (EMEC); Houlton Water Company (HWC): and Van Buren Light and Power (VBLP).

[44] As noted by MPS in its December 21, 2007 Comments, studies are currently underway to determine the feasibility of extending the MPC to interconnect with New Brunswick.

New England's transmission cost allocation system distorts market signals and creates impediments to sourcing remote generation.

1. Transmission pricing policies distort generation siting decisions

While extensive transmission investment is under consideration in Maine, ISO-NE's transmission pricing policy may inhibit its development. When new transmission is needed to preserve or enhance "reliability" as defined by the ISO, the costs of that transmission are socialized and charged to all customers around New England. Although socialization may be appropriate when a project provides benefits that are truly region-wide, the practice has not been limited to such projects. For example, over the past few years, there have been major new internal transmission upgrades in Connecticut and Massachusetts, the costs of which have or soon will be recovered from customers throughout the region because these projects meet the RTO's Open Access Transmission Tariff's (OATT) broad definition of reliability upgrade. There are also several large transmission projects under study in Maine, which may also seek cost recovery under the OATT.

There are two problems with this approach. First, it can easily be argued that it is neither fair nor efficient for electricity customers in Maine, for example, to be forced to carry the costs of a new transmission line whose purpose is to move power into a small sub-region, such as the southwest corner of Connecticut. Nor is it particularly fair for consumers in Connecticut to pay for transmission costs that are attributable to improving reliability conditions in Maine.

Second, this cost socialization also tends to distort the choice of resources built to serve constrained areas. In theory, the market should signal to consumers the relative economics of, for example, generation built in southwest Connecticut or generation built elsewhere that is less expensive, but that would require additional transmission to be built to transport the power. The economic solution is to build the more expensive southwestern Connecticut generation unless the price premium for construction is so great that it justifies building the necessary additional transmission and importing power from elsewhere. However, under the ISO socialization approach, the full cost of the transmission needed is masked from the point of view of consumers in southwest Connecticut, potentially leading them to prefer to import power from other regions even when it is uneconomic to do so. This, in turn, leads to overinvestment in transmission for which all of New England, including Maine, is forced to pay.[45]

Finally, the *status quo* cost allocation, whereby a transmission owner can socialize the cost of its project throughout the region, may make it easier for projects to be developed by exporting costs to other states. This can lead to more transmission than is needed and/or transmission in lieu of a more efficient generation (or demand-side) solution.

2. Transmission and market costs are not allocated in a manner to facilitate access to remote generation

[45] This is not always the case, however. For example, Connecticut has solicited proposals for capacity to be sited locally.

In addition to the inequities created by socialization, the transmission cost allocation and market regimes also undermine the development and delivery of the diverse resources that the region needs. First, it is unclear how transmission built primarily to connect the region with remotely-sited diverse resources would be treated, in that such transmission might not be viewed as a reliability project. This becomes particularly complicated when the transmission at issue is on the Canadian side of the border. Second, new transmission will likely increase energy prices in Maine. Under the ISO-NE market structure, energy prices have been lower in Maine than elsewhere in New England due to relatively low congestion costs and energy losses.[46] In recent years, Maine's energy costs have been from $40 to $90 million per year below the New England average costs at the New England Hub. These savings derive from the amount of generation within Maine coupled with physical constraints that limit exports to the south, as well as from loss-related effects. Additional new transmission in Maine could reduce or even eliminate this differential, depending on both the scale of the transmission upgrade and on the amount of additional power flowing from, or through, Maine.

Moreover, the decision-making paths for investments in generation and transmission are often separate. Transmission investment decisions are generally made by transmission owners subject to relevant approvals, and generation investment decisions are made by market participants subject to a different set of regulatory approvals. The fact that the two decision-making and approval processes happen separately from one another and on timelines that are not under the control of any one party increases the complexity of getting projects financed and approved.

In sum, the *status quo* creates powerful disincentives to developing transmission to access needed resources. Energy price increases to Maine consumers that may result from new transmission upgrades in Maine and the allocation to Maine consumers of costs to build transmission to serve other political jurisdictions do not promote the interest in siting new transmission in Maine and other resource states.

3. <u>Transmission planning does not adequately consider resource adequacy or diversity goals.</u>

Although resource diversity would provide important reliability and environmental benefits to the region and to sub-regions that are seeking access to renewable resources, it is not given much importance in *status quo* resource planning processes. As discussed in Section II, in recent winters the region has seen natural gas supply shortages that have threatened the reliability of the grid. In addition, the region will not meet the environmental goals embodied in RGGI and the state RPSs without harmonizing these goals with transmission planning and decision making in the region.

Transmission development in the region is driven by a process whereby utilities propose projects subject to consideration by ISO-NE and ultimate approval of the applicable state regulatory authorities. There is no explicit process at the regional level to examine whether the utility-proposed projects are adequate to meet the region's generation needs, nor whether there are generation alternatives to the transmission projects proposed.

[46] See Figure 1.

Furthermore, although resource diversity would provide important reliability and environmental benefits to the region, it is not given much importance in *status quo* planning processes. As discussed in Section II, in recent winters the region has seen natural gas supply shortages that have threatened the reliability of the grid. In addition, the region will not meet the environmental goals embodied in RGGI and the state RPSs without harmonizing these goals with transmission planning and decision making in the region.

C. RTO Governance and Policy do not Appear Geared to Least Cost Solutions.

ISO-NE does not have sufficient incentives to motivate it to seek least cost solutions for consumers, and it is not accountable to regional governmental authorities.

1. ISO-NE is not responsible for consumer costs.

ISO-NE is responsible for: (1) reliable operation of New England's bulk electric power system; (2) provision of centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines; (3) development, oversight and administration of New England's wholesale electricity markets; and (4) management of the region's comprehensive bulk electric power system and system planning.

ISO-NE's decision making is guided by the following objectives:

> **ISO Objectives:** The Objectives of the ISO as the RTO for the New England Control Area are (through means including, but not limited to, planning, central dispatching, coordinated maintenance of electric supply and demand-side resources and transmission facilities, obtaining emergency power for Market Participants from other Control Areas, system restoration (where required), the development of market rules, the provision of an open access regional transmission tariff and the provision of a means for effective coordination with other control areas and utilities situated in the United States and Canada):
>
> > (a) to assure the bulk power supply of the New England Control Area conforms to proper standards of reliability;
> >
> > (b) to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services (including Operating Reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participant to receive compensation through the market for a service it provides in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets;
> >
> > (c) to provide market rules that (i) promote a market based on voluntary participation, (ii) allow market participants to

> manage the risks involved in offering and purchasing services, and (iii) compensate at fair value (considering both benefits and risks) any required service, subject to FERC's jurisdiction and review;
>
> (d) to allow informed participation and encourage ongoing market improvements;
>
> (e) to provide transparency with respect to the operation of and the pricing in markets and purchase programs;
>
> (f) to provide access to competitive markets within the New England Control Area and to neighboring regions; and
>
> (g) to provide for an equitable allocation of costs, benefits and responsibilities among market participants.[47]

While ISO-NE has the responsibility to ensure reliability and competitive markets, <u>nothing in its mission or objectives focuses directly on cost containment or price reduction</u>. Recently the D.C. Circuit Court of Appeals found that FERC could not reasonably delegate its obligation to ensure that the rates in various contracts between ISO-NE and certain generators were reasonable because FERC had provided no evidence that ISO-NE had the incentive to bargain for lower prices:

> "Although the system operator plainly has an incentive to ensure that system-critical power is available to ensure grid stability and reliability, *FERC neither in its decisions nor at oral argument was able to identify incentives driving ISO-NE to bargain for low prices*."[48]

Further, while rates designed by ISO-NE and ISO-NE's administrative costs are subject to a determination by FERC that they are just and reasonable and do not impose excessive costs on consumers, ISO-NE does not have criteria built into its decision making process to ensure that the rates that flow from its initiatives are no higher than necessary.[49]

The lack of ISO cost control incentives also derives in part from the ISO's contractual relationship with the New England transmission owners. A transmission owner's participation in an RTO is voluntary.[50] ISO-NE's operation as the RTO is through a five-year contractual arrangement with the New England transmission owners.[51] ISO-NE's obligations as

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[47] ISO-NE Open Access Transmission Tariff (OATT) I.1.3.
[48] *NSTAR Electric & Gas Corp. v. FERC*, 481 F.3d 794, 803 (D.C. Cir. 2007). (emphasis added.)
[49] *Cf,* 35-A M.R.S.A. § 301 requiring rates for public utilities to be just and reasonable, prohibiting unjust and unreasonable rates, directing the Maine PUC in determining just and reasonable rates to provide revenues to the public utilities necessary to perform its public service and to attract necessary capital on just and reasonable terms; and allowing the Maine PUC to consider in determining just and reasonable rates whether the utility is operating as efficiently as possible and is utilizing sound management practices including the treatment in rates of executive compensation.
[50] *See, Atlantic City Electric Company v. FERC,* 295 F.3rd 1 ("Atlantic City")(D.C. Cir. 2002)("Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets").
[51] *See,* Transmission Operating Agreement § 10.1.

the RTO include transmission system planning and the approval of transmission projects in the regional cost allocation scheme.[52] Transmission owners are, obviously, in the business of building and owning transmission and this business can be profitable. Within an RTO like ISO-NE, the Federal Energy Regulatory Commission allows transmission owners to receive special incentives to build transmission, and these incentives apply even when there are cost overruns on transmission projects. This combination of interests of the RTO and the transmission owners could be problematic. Transmission owners have a profit motive to build transmission. ISO-NE has an incentive to perpetuate itself as an RTO. Because ISO-NE serves as the RTO under contract with the transmission owners, the RTO does not have an incentive to serve as a check on the profit motives of the transmission owners, even if they are adverse to the public interest. Thus, the lack of cost control incentives combined with the structural relationship of the RTO to the transmission owners could lead to an overbuild of the transmission system at the expense of consumers.

2. <u>ISO-NE governance is not accountable.</u>

A ten-member,[53] independent board governs ISO-NE. The ISO-NE Board has exclusive decision-making authority for ISO-NE, including ultimate authority over the ISO-NE Tariff and Market Rules and ISO-NE's operating and capital budgets. While the board must "possess a cross-section of skills and experience . . . to ensure that ISO has sufficient knowledge and expertise to act as the RTO for New England" and must have at least three directors with prior relevant experience in the electric industry, preferably from New England, there is no requirement that Board members have any regulatory experience or experience representing consumers.

ISO-NE Board members serve staggered three-year terms, subject to certain age and term restrictions. A committee (the "Nominating Committee") composed of members of the existing ISO-NE Board and NEPOOL Participants, as well as one representative of the New England Conference of Public Utility Commissioners ("NECPUC"), nominates a slate of candidates to fill open positions on the ISO-NE Board. The slate is subject to an advisory vote by NEPOOL which can result in the nominating committee changing the slate. Ultimately, the Board has final approval of the slate of Board candidates. Since the implementation of this process in 2005, the slate recommended by the nominating committee has been supported by NEPOOL and approved by the ISO-NE Board of Directors.[54]

FERC and many consumer advocates are struggling with ways to address consumer concerns about the lack of incentives to achieve cost reduction and value from the RTO and RTO-administered wholesale electric markets. One approach suggested by public power interests is to require ISOs and RTOs to have a cost control mission. Given the absence in

52 ISO-NE OATT II.48.5.

53 The ten members are comprised of 9 voting members and the ISO-NE Chief Executive Officer, who serves as a nonvoting member.

54 While the ISO-NE Board has approved all directors nominated by the nominating committee, one such director was not permitted to serve on the Board because FERC denied ISO-NE's application (on behalf of the approved director) to hold interlocking positions. *James S. Pignatelli,* 111 FERC ¶ 61,496 (2005) (rejecting application to hold interlocking positions as director of ISO-NE and chief executive officer of non-affiliated utility, finding, among other things, that potential adverse effects on competition warranted denial of the application).

the ISO-NE tariff of a specific cost reduction or cost control mission or objective, there appears to be a lack of connection between actions taken to promote reliability and the cost of such actions. Some public power advocates have suggested that this gap could be addressed in part by adding cost-control or rate reduction to RTO objectives or mission. With respect to ISO-NE, Massachusetts Municipal Wholesale Electric Company (MMWEC) and the Connecticut Municipal Electric Energy Cooperative (CMEEC) have stated:

> In our view, it is essential that ISOs and RTOs be fully aware of their obligation to provide or facilitate the provision of reliable service to consumers at the lowest reasonable cost. As that does not appear presently to be the case (at least in New England, if not elsewhere), we urge the Commission to make that obligation express in this proceeding. In terms of implementation, this obligation should be incorporated explicitly into each ISO or RTO's mission statement and governing documents. In addition, the Commission's application of the "just and reasonable" standard to filings made by ISOs and RTOs should take into account whether the action proposed by the ISO/RTO is consistent with that obligation.
>
> The need for these measures springs in part from the existing imbalance in ISO/RTO incentives. As system operators, they have substantial incentives to make planning and operations decisions that facilitate reliable operation of the system, which is an appropriate goal. However, because they do not pay the costs resulting from their decisions, they have no incentive (either express or implicit) to minimize those costs or their impacts on consumers. Nor is there meaningful competitive pressure among ISOs or RTOs (which are natural regional monopolies) to provide system-operation or market-administration services at least cost. As a result, ISOs and RTOs are not naturally inclined to consider either the direct or indirect costs of their actions. Instead, from our vantage point as consumers, it appears that ISOs and RTOs are inclined to opt for the easiest or theoretically purest approaches to system administration or market design without adequately considering likely consumer impacts.[55]

Similarly the American Public Power Association (APPA) supports requiring modification of RTO mission statements and charter documents to include an explicit RTO obligation to reduce electric power costs to consumers. APPA notes:

> At present, RTOs pursue as their core missions the maintenance of grid reliability and the development of administrative markets for a plethora of products. Little or no attention seems to be paid to whether end-use electric consumers in fact benefit from these markets. Maintenance of grid reliability seems to take clear precedence over costs to consumers. While APPA certainly agrees that reliability is a core mission of RTOs, it should be paired with cost reductions and demonstrable benefits to consumers.[56]

[55] Massachusetts Municipal Wholesale Electric Company comments, dated September 14, 2007, in AD07-7 at 5. (citations omitted).
[56] NSTAR comments, dated September 14, 2007 in AD07-7.

Others have suggested that the independent board should be maintained but there should be a requirement to have board members with experience serving or representing consumers:

> The Commission should consider providing guidance on the composition of boards to include more consumer representatives. The transformation need not be disruptive but can be accomplished as ISO-NE board members are replaced over time. After transition, the composition of the board would be sufficiently diverse to ensure proper consideration of the concerns of all stakeholders.

Recently Maine Senator Susan M. Collins and Connecticut Senator Joseph I. Lieberman asked the Government Accountability Office (GAO), for an investigation by GAO into whether ISOs and RTOs are sufficiently focused on the costs and benefits of their actions. In a May 21, 2007 letter, these Senators asked the GAO to "begin an investigation into ISO and RTO costs, structure, processes, and operations." GAO Letter at 2. Explaining the need for the investigation, Senators Collins and Lieberman questioned whether RTOs and ISOs were "living up to their full potential with respect to improving and reducing costs" and whether they had, "adequate incentives to minimize costs." *Id*. at 1. The Senators asked that the GAO report on several questions relating to whether RTOs and ISOs have: (1) mission statements that include obligations to control administrative and operational costs, and the cost impacts of its market-design decisions, in order to keep costs low for consumers; (2) incentives to ensure that costs to consumers are as low as reasonably possible; and (3) mechanisms to identify, assess, track, and monitor the cost impacts of its decisions at the retail consumer level. The Senators also asked the GAO to identify for each RTO/ISO:

> (a) what process is in place to ensure that an evaluation of the costs and benefits of the market design proposals is conducted prior to their submission to the FERC for approval; and,
>
> (b) what role do market participants and other stakeholders (*e.g.,* state commissions) play in the development, consideration and submission for approval to FERC and approval of (i) new market design proposals; and (ii) the RTO/ISO annual operating budget?

Id. While the GAO has agreed to conduct the requested study, its initiation has been delayed pending the availability of appropriate GAO personnel resources. The questions asked by the Senators and the concerns expressed by consumer groups indicate that there is a growing concern that RTOs in general and ISO-NE in particular are neither required by their mission, nor have the incentive built into their cost structure or regulatory review to ensure that costs to consumers are as low as reasonably possible.

V. ALTERNATIVES TO THE *STATUS QUO*

In our "Interim Report" to the Legislature in this proceeding, we identified three alternatives to the New England RTO:

1. working within the current ISO-NE framework to address and correct the identified inequities;

2. withdrawal by Maine's utilities from ISO-NE without creating a new inter-jurisdictional market structure through the creation of one or more independent transmission companies ("ITC"); and

3. developing a market with one or more of the Canadian Maritime provinces.

We found that there are no structural or legal impediments to pursuing these alternatives. However, we identified several threshold questions that would need to be resolved for each to be further developed.

In the following sections, we provide an assessment of each alternative, framed in terms of how well it would meet the region's challenges. We do not believe that it is in Maine's interest to take a purely parochial view of its relationship with the region. Rather, alternatives to the *status quo* must address the inequities of the current system, but must also provide a vehicle for the delivery of the generation resources the region requires in an economically efficient and equitable manner. Each of the alternatives described below could achieve these goals.

A. Regional Market Reform and Expansion

In the Interim Report, we found that the current regulatory system, if reformed, could provide a reasonable alternative to the *status quo*. After further analysis, we reaffirm that finding. There are powerful synergies provided by the regional market. These include: a platform for retail competition; a regional approach to energy resource planning; sophisticated dispatch protocols and market systems that optimize generation efficiency; and a liquid market with many buyers and sellers.

The economies of scale provided by the size of the region allow it, through ISO-NE, to have access to a vast array of resources. Engineering, economic and regulatory professionals can be deployed to regional priorities in a manner that would be difficult to replicate in smaller systems. The regional system planning process and market system aid the region with its six political subdivisions to coordinate the electricity market and transmission system. In addition, ISO-NE has become a platform for regional policy development through vehicles like Scenario Analysis and various white papers periodically produced.

However, despite these powerful attributes, the current market system may not achieve the public policy goals established by the states or demanded by consumers. Reform is necessary to achieve greater fuel diversity and to enable the region to meet state environmental policies. Because of the compelling need for fuel diversity and alternative resources to maintain system reliability and meet state policy goals, expanding the reach of the existing market is a critical component of market reform. Redesigning transmission cost allocation is essential to this expansion, as well as to foster an economically efficient and equitable market in the region. As described in Section IV, transmission costs within New England are allocated in an inequitable and economically inefficient manner and investment decisions are distorted by socializing certain transmission costs. Most worrisome, however, is the fact that transmission to resource regions that will enable diverse resource access to New England may not be eligible for socialization under the existing ISO-NE tariff.

Despite the good efforts of regional regulators to address the infirmities of the region's transmission cost allocation regime, in the near term, transmission cost socialization is unlikely to be changed to eliminate inequities. The regional agreements establishing the transmission cost allocation regime are due to expire by the end of 2010. It is unlikely that a regional process could achieve the necessary changes before the end of the terms of the existing agreements. In addition, unless the Commission pursues litigation to drive alternatives, there does not appear to be an immediate vehicle with which to pursue reform. Due to these practical considerations, reform of the transmission cost allocation regime within New England must follow a near-term and a long-term track.

In broad outline, reform of the transmission cost allocation regime within New England should proceed along the following lines:

First, the long term objective should be to move to a coherent and economically rational system of cost assignment. As articulated in more detail in section 2.a. below, both fairness and economic efficiency are better served when costs are recovered in proportion to the benefits received. It is simply not the case, for example, that customers in Maine benefit to any significant extent from system upgrades intended to preserve reliability in southern Connecticut, or vise-versa, notwithstanding the fact that Maine and Connecticut are interconnected within the New England bulk transmission system. While the identification of the principal beneficiaries in terms of reliability and economic benefits may be complex, achieving a reasonable approximation of relative benefits should not be beyond the competence of the engineers and economists in the New England market. Moreover, other jurisdictions have developed FERC-approved methodology that accomplishes this result.

Second, in light of the practical difficulties of achieving quickly the objective of a cost assignment regime that recognizes the widely different level of benefits obtained by different groups of customers from any particular transmission project, there should be immediate recognition, within the existing cost assignment regime, of the regional value for reliability of projects that will increase the availability of diverse generation (including especially renewable generation that will assist all of New England in meeting RGGI and related goals). It would be anomalous even within the current regime, for example, to deny regional cost recovery treatment to a line built within Maine that had the effect of substantially increasing the ability of power produced by wind and other renewable generation in Maine and the Maritimes provinces to reach markets in southern New England.

Achieving the long term objective of a system that assigns costs principally based on benefits, and the near term assurance that the costs of projects that clearly benefit the major load centers of New England are substantially assigned to those areas, will remove two important impediments to building major transmission facilities within Maine, and will also lead to a more efficient allocation of resources to transmission throughout the region. However, another important impediment remains. This is the loss of the current relative price advantage that Maine enjoys over the rest of New England due to the limited capacity of the transmission system from Maine to the south. Even with a more rational and fair system of collecting the direct costs of transmission, in which the costs of new transmission built to give access to renewable generation in Maine and the Maritimes to the southern New England market are assigned to those markets, Maine customers might still suffer financially from the increase in transmission capacity as a result of the elimination of the constraint between Maine and southern New England and the accompanying loss of the locational energy price differential.

1. Near-term reform

Although comprehensive reform of the transmission cost allocation system is necessary to create an economically efficient and equitable structure for New England, regional reliability and state policy goals can be enabled by the existing transmission cost allocation regime within the plain meaning of the current ISO-NE tariff. Moreover, the market effect of transmission investment that can discourage resource states like Maine from expanding its transmission system to accommodate exports can be resolved in the near term. Lastly, the imminent formation of the New England State Committee on Energy (NESCOE) may provide greater public involvement with ISO-NE and the regional stakeholder process.[57]

a. Resource Diversity Enhances Reliability – transmission to open these areas to generation development ought to be socialized.

According to the ISO-NE tariff, maintaining and enhancing transmission system reliability is the touchstone for determining that a transmission investment will be socialized. Specifically, a Reliability Transmission Upgrade (RTU) is defined as:

> Those additions and upgrades not required by the interconnection of a generator that are nonetheless *necessary to ensure the continued reliability of the New England Transmission System*, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved *with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies*.[58]

As discussed above in Section II, the region's overdependence on natural gas to generate electricity has caused reliability concerns in recent years, in particular, during the cold snap in 2004 and following Hurricanes Katrina and Rita in 2005 when electricity

[57] ISO-NE "strongly supports" the involvement of NESCOE and other high-level policy groups. (See ISO-NE December 21, 2007 Comments at http://mpuc.informe.org/easyfile/easyweb.phpfunc=easyweb_query, reference Docket No. 2006-364)
[58] ISO-NE OATT II.1.126 (emphasis added).

supply was threatened by inadequate natural gas supply.[59] ISO-NE's Regional System Plan (RSP) identifies the regional needs for fuel diversity for system reliability.[60] Specifically, the RSP recommends that the region develop alternatives to energy technologies to reduce reliance on natural gas."[61] Thus, transmission needed to access these diverse resources is clearly within the definition of an RTU. Moreover, such upgrades would not be classified as upgrades "required by the interconnection of a generator" because they would, in most circumstances, be providing a corridor to access a number of renewable resources, rather than interconnecting a particular generating unit.

In its Scenario Analysis, the ISO drew the link between accessing the remote generation resources and reliability. The ISO included a renewable resource scenario that would lessen New England's reliance on natural gas. The renewable resource scenario met many of the region's policy goals but, the ISO determined that accessing remote "low-or-zero CO2 emitting resources will "require the region to build substantially more transmission to move this power to the load centers."[62]

Transmission to northern New England, or through northern New England to Eastern Canada, could enhance the reliability of the region by providing access to regions rich in non-gas-fired generation. Among the renewable resources identified by ISO-NE in its Scenario Analysis as having diversity benefits is wind. ISO-NE estimates that a large percentage of these possible resources, a minimum of 1,000 MW, would be located in Maine. As noted in Section III, some estimates place Maine's wind energy potential at 4,000 MW.[63] Additionally, ISO-NE recognizes that Eastern Canadian Premiers and Canadian utilities have announced a strategy to build 4,000 to 6,000 MW of surplus hydro-electric resources.[64]

ISO-NE is currently studying proposals for a transmission line to, or through, northern Maine. However, a determination of whether the line will qualify as an RTU is forthcoming. The Commission believes transmission solutions into northern Maine, Eastern Canada and the remote regions of other states like New Hampshire, meet the clear meaning and intent of ISO-NE's tariffed definition of an RTU, because they will aid the region in diversifying its resource mix, and enhance the reliability of the regional system. Socializing these transmission resources as RTUs is an essential component of interim reform.

Recent Comments filed by the ISO-NE are encouraging in this regard, although it remains to be seen how transmission projects will be planned and coordinated in actual practice, as well as how costs will be allocated. In particular:

> The ISO believes that the Regional System Planning process currently utilized in New England – including the Planning Advisory Committee ("PAC") mechanisms recently strengthened and clarified in the ISO's filing of a new

[59] See 2004 and 2005 ISO-NE Annual Markets Reports Final Cold Snap Report, October 12, 2004.
[60] 2007 Regional System Plan (RSP-2007), e.g. at p 6.
[61] RSP-2007 at 3, 6, 12.
[62] Scenario Analysis at 7.
[63] See October 30, 2007 presentation to Maine's Wind Power Task Force by Sustainable Energy Advantage, LLC
[64] Stephen G. Whitley presentation to Transmission Committee meeting "New Canadian Hydro-power Initiatives," July 2006 at 7.

Attachment K to its Open Access Transmission Tariff ("OATT") – provides a solid platform for coordinating input from stakeholders and regulators, and for the collaborative development of creative responses to pressing regional problems. With the recent enhancements, the PAC will be empowered to prioritize "economic studies" to be performed by the ISO that will consider transmission upgrades that can produce economic benefits for the region as well as encourage market responses (including efficiency and demand response) to the identified needs. The ISO's recent "scenario analysis," performed in collaboration with state officials and market participants, can inform this effort.

The PAC can be readily employed, for example, to bring diverse stakeholder interests together to consider how achievement of environmental and electricity cost goals – and mitigation of fuel diversity risks – can be furthered through a concerted, regionally supported effort to economically integrate areas that are rich in renewable resources or can host other non-CO_2 emitting generation facilities.[65]

b. Transmission expansion could serve Maine's interests.

Maine, as well as the region, can benefit if the region invests its resources here. Northern Maine (Aroostook County and parts of Washington County) are not directly interconnected to the rest of Maine. Northern Maine is part of the Maritimes Control Area and is connected to Maine and ISO-NE with transmission through New Brunswick. The Maritimes Area does not yet have the structures and liquidity to support a functional wholesale market, as a result competition is northern Maine has not been achieved.[66] After a standard offer solicitation in 2006 that yielded only one bidder, the Commission found that the experiment with competitive markets in northern Maine was an "obvious failure."[67]

Maine has considered and studied interconnecting northern Maine to the New England market for decades. Movement forward with an interconnection has been stymied by the sheer cost of the endeavor. Interconnecting northern Maine could cost hundreds of millions of dollars, far more than ratepayers in northern Maine could afford. Now, however, a convergence of events makes an interconnection plausible. Advances in wind energy technology have commercialized wind as a generation resource. Aroostook County is already the site of the largest commercial wind energy facility in New England at Mars Hill. Soon, a development on Stetson Mountain in Washington County will take that mantle, with the construction of a 57 MW wind facility. This generation, along with nearly 1,000 MW of additional proposed generation, create substantial energy and economic development opportunities in northern Maine. The confluence of technological advances that make wind commercially viable, the resources of ISO-NE, and state environmental policies that provide incentives for new renewable generation support a transmission interconnection with northern Maine. ISO-NE, along with CMP and MPS, is currently studying an interconnection. The sophistication, liquidity and size of the regional market that make this study and potential interconnection possible will be difficult to replicate in the other alternatives presented below. More importantly, socializing the costs of a

[65] See December 21, 2007 comments of ISO-NE at page 3.
[66] See e.g., Docket 2006-513 at http://mpuc.informe.org/easayfile/easyweb.php?func+easyweb_splashpage.
[67] See Order Rejecting Standard Offer Bids, November 16, 2006, Docket 2006-513

northern Maine project by designating it an RTU would eliminate the cost barrier that has prevented development to date.

c. Market effects of transmission expansion must be managed.

As discussed above in Section IV, one critical flaw of the existing regime is the disincentive it creates to remove transmission constraints when an exporting zone, like Maine, will see electricity supply prices increase as a result. It is unreasonable to expect consumers in an exporting region to support the development of new generation and transmission investment to serve the region if, as a result, prices in the resource state increase. This is especially so when the burden of paying for transmission costs rests, in part, on the exporting state.

On the other hand, the Commission believes that it is not sound policy for a state like Maine that is export constrained to maintain that constraint as a specific strategy. As we discussed in the Interim Report, generation usage and concentrations change over time. A transmission constraint can work for or against a party at any given time, and reverse its impact if conditions change. Taking the long view, which is appropriate for transmission investments that can have 50 year life spans, congestion at any one moment may not represent prevailing conditions over the life of a transmission investment.

A reasonable approach, therefore, is one in which consumers in export states like Maine are protected from market impacts for a period of time, but not for the life of the transmission investment. A vehicle to achieve this could be a contract for differences, or CFD. A CFD is a contract between two parties, providing that the seller will pay to the buyer the difference between the current value of an asset and its value at contract time. In the energy context, a CFD could capture the value created by relieving congestion as a buffer for consumers in export zones against the market costs associated with transmission investment.

The Commission was recently granted long-term contracting authority[68] by the Legislature. This authority enables the Commission to acquire contracts for capacity and energy to maintain resource adequacy. Although currently not extended to financial instruments such as CFDs, the Legislature could amend this authority if it considered the CFD approach to have merit. In the alternative, there may be other statutory[69] vehicles that will achieve similar results.

There are several issues to be resolved before this approach is workable or certain to provide benefits. For instance, whether consumers to our south, generators to our north, or both participate in the CFD needs to be determined. Nevertheless, a CFD for a limited term could insulate Maine consumers from market effects, thereby making transmission investment in the interim period more likely.

[68] Resolves 2007, Ch 54. See also, *Inquiry Regarding the Reentry of Electric Utilities into the Energy Supply Business,* Docket No. 2007-317.
[69] i.e., 35-A MRSA, Section 3204(6) provides for limited utility generation entitlement ownership.

d. NESCOE may provide more robust public sector engagement of ISO-NE and the region's stakeholder process.

On June 25, 2004, the New England Governors filed a petition[70] at FERC for a declaratory order establishing the New England States Committee on Electricity (NESCOE) as New England's regional state committee (RSC). NESCOE was formed as part of the FERC initiative toward RTO formation. FERC believed that an RSC was necessary because neither RTOs, ISOs, Transmission Owners or stakeholder groups such as NEPOOL could offer the political representation and accountability needed to balance various public policy objectives on behalf of the states in the region. [71] Initially, NESCOE will focus on developing and making policy recommendations related to resource adequacy and transmission system planning. However, as a component of near-term reform, NESCOE could engage ISO-NE and the regional decision-making processes to ensure that public and state interests are adequately treated, and that ISO-NE is properly accountable for its decisions and actions.

2. Longer-term reform

In the Interim Report (and in Appendix A), we demonstrate how transmission cost allocation in New England can create inequities within the region. The transmission cost allocation regime in New England also creates substantial inefficiencies and is an impediment to meeting the region's fuel diversity, RPS and RGGI goals. In addition, the *status quo* lacks cost control incentives and public accountability. These problems must be addressed in longer-term market reform. The current RTO contracts with the regional utilities, including CMP and BHE, will be up for renewal, reform or termination in 2010. The following reforms are among those that should be considered at that time.

a. "Beneficiaries pay" transmission cost allocation methods will promote the efficient and equitable allocation of transmission investments in the region.

Transmission reform moving toward a "beneficiaries pay" methodology is more economically efficient and in keeping with market principles than socializing costs across the region. Specifically, in a market that mixes competition with regulatory intervention, transmission projects must be accompanied by mechanisms that allocate costs and benefits in a way that approximates as closely as possible the *economic consequences* that would follow from a market response. In other words, transmission cost allocation should allow those who will bear the high costs of congestion or degraded reliability to decide whether the planning results are sufficient to warrant investment in the proposed solution. Such an allocation will provide appropriate price signals for load to make consumption decisions. State regulators will be able to determine whether the benefits of proposed transmission projects which will reduce congestion costs and improve local reliability, will exceed the project costs. By contrast, a failure to align costs and beneficiaries can lead to overbuilding the transmission system and other inefficiencies. Dr. William Hogan provides a good explanation of the adverse effect on efficient resource development of perpetuating the socialization of transmission costs.

[70] The Petition was amended on January 11, 2005.
[71] *See,* SMD NOPR; "White Paper, Wholesale Power Market Platform," Docket No. RM01-12-000, April 28, 2003.

> There is a strong interaction among transmission, generation and efficiency investments. But the relationship is not so simple as straight competition for investment dollars. There is a mixture of substitutes and complements. When considering delivery to a load center, distant generation and efficiency investments require transmission to move from the source of available energy to the consumption destination. Therefore, such generation and efficiency investments are complements of transmission. The distant generation or efficiency combined with transmission then substitute for generation or efficiency investments at the load center. The mix of complements and substitutes can be complicated by many network interactions under the general topic of loop flow or the requirements of voltage support. But it is too simple to say that transmission is either only a substitute or a complement. Transmission complements some electricity investments and substitutes for others. It follows that transmission investment rules and cost allocations can have a significant effect on the incentives for investment in generation and efficiency. If we socialize the cost of transmission investments, the result would tip incentives towards more of those generation and efficiency investments that were transmission complements. At the same time, socializing the cost of transmission investments would blunt the incentives for load center efficiency or distributed generation investments that would be transmission substitutes. [72]

Because of the inefficiencies of the current cost allocation scheme and its impact on consumers, it is critical that transmission cost allocation reform be part of any new RTO agreement.

b. Regulators in the region lead.

In the Interim Report, we indicated that the New England Conference of Public Utilities Commissioners (NECPUC) had passed a resolve[73] to consider alternatives to the existing transmission cost allocation regime. In June 2007, the NECPUC staff completed a report on transmission cost allocation. [74] The report outlined the current ISO-NE cost allocation methodology and alternative methodologies approved by FERC for other ISOs and RTOs. The NECPUC staff also provided individual state staff views on the pros and cons of each methodology. Finally, the report lists the following possible alternatives that may be considered to provide incentives for siting transmission in resource states and identify beneficiaries of proposed transmission upgrades:

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72 William Hogan statement, Attachment 1 at P.5 to MPUC protest in Docket ER03-1141 dated August 21, 2003.

73 NECPUC Resolution to Study Alternatives to the Current Transmission Cost Allocation Methodology. This resolve is appended as Attachment 1, to the NECPUC Staff Report on Transmission Cost Allocation.

74 NECPUC Staff Report on Transmission Cost Allocation, this report can be viewed at the following link http://www.maine.gov/mpuc/industries/electricity/NECPUCStaffReportonTCA_000.pdf

1. Retain existing cost allocation methodology.
2. Develop a hybrid methodology perhaps combining features of the MISO and SPP cost allocation methodologies, both of which allocate a portion of the costs regionally and a portion to beneficiaries based on an objective load flow methodology.
3. Develop a hybrid methodology discussed above combined perhaps with some aspects of the California renewable interconnection approach.
4. Develop a hybrid approach that blends a decision on cost allocation methodology with reform of the planning process to promote more efficient use for all resources, including funding options for least cost alternatives.

The report describes the methodology used by the Midwest Independent System Operator (MISO) and the Southwest Power Pool (SPP) which uses a “hybrid” methodology in which it combined a socialization methodology with one that determines beneficiaries based on a specific metric. In a recent case FERC described the beneficiary determination based on a metric as follows:

> First, an RTO can allocate costs using a well-defined modeling approach that identifies beneficiaries based on specific criteria or metrics (*e.g.,* the alleviation of reliability violations or reductions in production costs or locational marginal prices). For such a method to provide *ex parte* certainty, the key criteria, metrics and assumptions must be set forth in the tariff with sufficient specificity that they are not relitigated each time a new project is approved by the RTO. [75]

FERC further noted with approval that MISO and SPP had combined both a socialized cost approach with a beneficiary-metric approach:

> Thus, Midwest ISO region, for instance, uses a combination of these approaches in allocating transmission costs within their regions. It uses (i) a fixed, postage-stamp cost allocation of a portion of high voltage facilities at or above 345 kV and (ii) a modeling approach to allocate the remaining costs of those facilities to the beneficiaries of each project. This region did not reach complete consensus on all elements of these methodologies; however, the states in this region achieved general consensus on the appropriate voltage cut-off for the postage stamp allocation (345 kV) and the appropriate level of that allocation (i.e., 20% socialization). Southwest Power Pool, Inc. (SPP), similarly, received state support for its methodology, which allocates 33% of the cost of projects in its base plan across the SPP footprint and 67% to the zones that benefit from the project as measured by SPP’s MW-mile method.[76]

[75] *PJM Interconnection, LLC,* 119 FERC ¶ 61.063 P.66 (2007).
[76] *Id.,* P 68.

At its July 2007 meeting, NECPUC Commissioners directed the staff to further investigate alternatives two and three. As a result, several NECPUC staffers are analyzing methodologies to eliminate economically inefficient transmission investment. Current development of and results from the hybrid methodologies will inform the staff work on possible longer-term alternatives for transmission upgrades. In addition, in the near term, given that NECPUC believes that adding renewable generation and imports to the New England power grid could qualify for cost socialization under the existing tariff, NECPUC is developing a request for ISO-NE to perform a study to determine the overall cost/benefit of adding these resources so the benefits can be compared against the cost of building or upgrading transmission to deliver the renewable power.

Cost allocation reform is unlikely to be resolved immediately. However, NECPUC's movement makes it likely, though clearly not certain, that when the next RTO agreement is negotiated in the region in 2010, transmission cost allocation could be a topic for compromise. Clearly, if the region moved toward a beneficiaries pay or hybrid regime, then many of the inequities and economic inefficiencies of the current system would be resolved.

c. RTO governance, cost and accountability must be addressed.

In addition to a long-term solution for transmission cost allocation, there are several other market reforms that should be addressed for long-term reform. As discussed above in Section IV, ISO-NE does not have the proper incentives to pursue least cost solutions or to serve as a check where there are incentives to increase consumer costs. RTO governance and policy should be more geared to least cost solutions and greater public sector involvement.

ISO-NE, as a quasi-governmental institution, works with very little public oversight compared to public institutions in Maine. It is not subject to open meeting or freedom of information laws. ISO-NE, though regulated by FERC, is not directly accountable to state governments in New England. As described in Section IV, concerns about public accountability led Senator Collins to request the GAO to investigate whether ISOs and RTOs are sufficiently focused on the costs and benefits of their actions, and to identify the role of stakeholders in the development and approval of market design changes and ISO/RTO operating budgets.

While Congressional initiatives are focused on solutions to some of these problems, Congress should not be expected to serve as the only avenue to enforce public accountability. New England regulators and policy makers should advocate directly for greater public accountability. As noted above, NESCOE may serve this role, at least in the interim.

3. <u>Risks, benefits and impact on consumer costs</u>

The Market Reform Option has the least transactional risk of all alternatives, but will be difficult to achieve. While the region has come together to advance common interests, where the relative economic positions of the states are at issue, regional consensus tends to be illusive. Moreover, this option is unlikely to lower electricity supply costs and while it will likely lower transmission costs for Maine consumers, it may not lower transmission costs for the region.

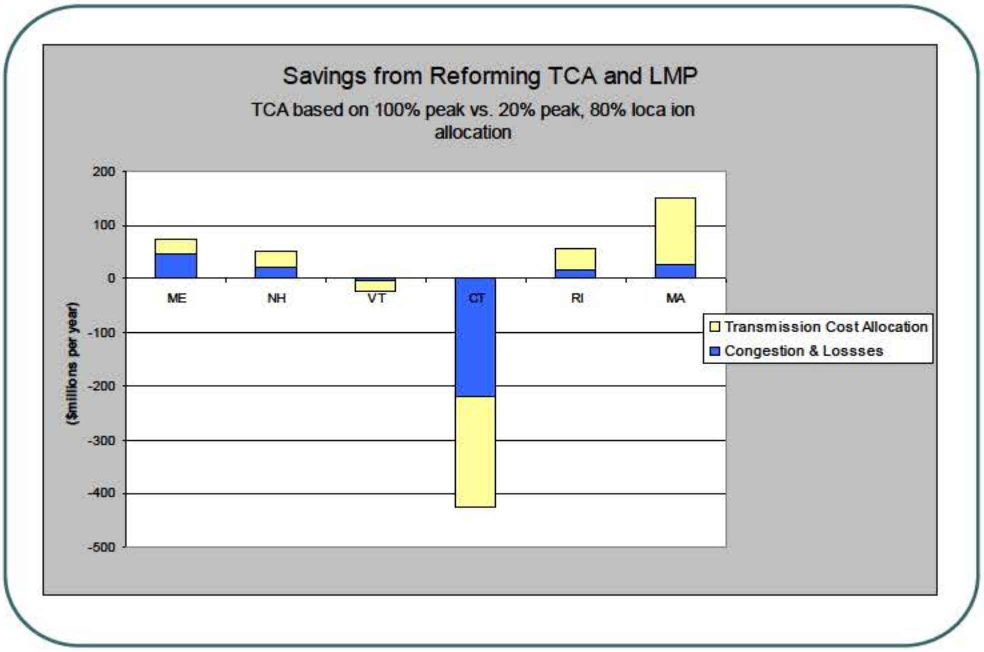
a. Transactional risks are low, but the region will be challenged to reach consensus on meaningful transmission cost allocation reform short of protracted litigation.

The Market Reform Option has certain known risks, but entails the least amount of transactional risk. Creating new structures and legal agreements take time and results rarely reflect precise expectations at inception. The Market Reform Option's greatest single attribute is that it is building on known and tested arrangements and regional bodies. This is also the Market Reform Option's single greatest weakness.

Historically, the region has failed to resolve important economic issues, short of litigation at the FERC, when cost shifting among states has been at issue. With respect to transmission, each of the long-term transmission cost allocation reform proposals will create winners and losers among the New England states. This is illustrated below in Figure 15:[77]

[77] Data from ISO-NE 2006 Regional System Plan

Figure 15 – Illustration of TCA Reform Cost Shifting



Although this graphical depiction is merely representative, it highlights the difficulties inherent in transmission cost allocation reform by showing the potential cost shifting among states. Regional collaboration on issues like this has not typically resulted in consensus, even when an outcome is justified by sound economics or other policy considerations. State individual interests tend to trump economic efficiency or equity.

Nevertheless, NECPUC's leadership in 2007 in analyzing alternatives to the *status quo* transmission cost allocation regime is promising. Indeed, if NECPUC continues its work and opens its internal staff process for a true regional collaborative to address the infirmities of the *status quo*, it is possible meaningful market reform could be achieved.

b. Retail consumer choice could be maintained; the region's environmental priorities would be achieved.

If meaningful market reform could be achieved, the benefits to Maine and the region would be substantial. First, transaction risks associated with the other alternatives could be avoided. Retail choice, which has provided some benefits for commercial and industrial customers in Maine, could be supported under the Market Reform Option, while other alternatives may not be able to support a retail market here. Further, the region's environmental priorities and fuel diversity needs could be met, making for a more reliable and efficient marketplace for consumers. In addition, it is likely that, through leveraging the resources of ISO-NE and the financial support of the entire region, transmission investment with the support of a powerful liquid market, would generate the most renewable resource development in the region, when compared to the other alternatives.

c. While some transmission costs could be avoided, other electricity costs are unlikely to change, and are likely to increase over time.

The Market Reform Option is likely to reduce transmission costs in Maine even under some circumstances where Maine's transmission needs dramatically increase, as shown in Appendix A. In any case, as indicated in Figure 15, the Market Reform Option is likely to shift costs among states.[78] It is unlikely, however, that electricity supply costs would decrease with this alternative. As ISO-NE indicated in Scenario Analysis, natural gas-fired generation will continue to set the energy clearing price in the region under all likely scenarios.[79] Thus, even though expanding the market will bring diverse generation into the mix, because of the structure of the regional market and standard market design,[80] the volatility and apparent sustained high cost of natural gas will continue to influence the region and Maine under this option.

In addition, capacity costs are not likely to decrease for Maine consumers under the Market Reform Option. In a recent filing with FERC, ISO-NE reported that over 6,000 MW of new capacity resources will be eligible to participate in the Forward Capacity Market (FCM).[81] The ISO also determined that all of New England will have a single auction, except Maine, which will have its own zone.[82] While Maine standing as its own zone should lower capacity prices here, several of the transmission projects under study in Maine may relieve that congestion, which will consequently raise capacity prices in Maine to converge with the rest of New England.[83]

B. Alternatives to ISO-NE: Maine ITC and Maine/New Brunswick Common Market

In the Interim Report the Commission identified two potential alternatives to ISO-NE: the formation of one or more independent transmission companies (ITC), comprised of Maine transmission owners; and, the formation of a common market with Maine and New Brunswick.[84] Either alternative could, if properly implemented, be superior to the *status quo* in

[78] However, as indicated in Appendix A, there are scenarios in which a beneficiaries pays model will increase consumer costs in Maine.
[79] Scenario Analysis at 6.
[80] The Uniform Clearing Price.
[81] *ISO New England, Inc.,* Informational Filing for Qualification in the Forward Capacity Market, dated November 6, 2007, Docket No. ER08-190, Transmittal Letter at 6.
[82] In press release on November 7, 2007, ISO-NE reported that transmission constraints potentially lock-in generation in Maine, creating the needs for a Maine-only capacity zone. ISO-NE also reported in that press release that "Additional transmission or resources in certain local areas will be needed in the future to eliminate constraints. Studies are underway to develop solutions that address existing and future local and regional transmission constraints."
[83] The transmission projects currently under consideration could result in such capacity price convergence unless or until new generation in Maine (or further north) is developed.
[84] This alternative could also include other Canadian Provinces, e.g., Nova Scotia, and Prince Edward Island. As a practical matter, however, because of New Brunswick's size and shared border with Maine, the differences between a combination of these four markets and a combination of only Maine and New Brunswick would be minimal with respect to much of the analysis. On the other hand, the smaller combination might reduce the complexity of the intergovernmental negotiations that would be required to achieve a new trans-border market. If this option is pursued, therefore, the best course is likely to be to seek a broader market that includes the three provinces but

meeting key fuel diversity and environmental policy goals. Each alternative could potentially reduce consumer costs in relation to the *status quo,* although, unless there are seams between the alternative system and ISO-NE, supply prices will continue to track with New England. However, each alternative has substantial implementation and transaction risks, and there could be implications in terms of FERC jurisdiction.

Under the Maine ITC and ME/NB Common Market alternatives, certain elements of the bulk power system would be similar, including: energy market costs, capacity adequacy costs, transmission costs (including the implications of socialization or beneficiary assignment), regulation (and other ancillary services), reserves, administrative costs, governmental oversight and control (state and federal), reliability, and market structure (both wholesale and retail). We will, therefore, discuss them together.

1. Common issues

a. Transmission utilities rights under the Federal Power Act

Both of these options require a decision by CMP and BHE to withdraw or not renew membership in the RTO. Requiring withdrawal or formation of a different transmission arrangement would interfere with the transmission utilities' right to develop rates and file for their approval under section 205 of the Federal Power Act. While FERC can determine whether such rates are just and reasonable, it cannot either require a utility to join an RTO or prevent one from doing so.[85] Thus, as we noted in our Interim Report, the decision to leave the RTO or form a new arrangement rests with the utilities.

b. Planning issues

Either alternative would better meet the goal of coordinated regional transmission planning that also considers generation adequacy and diversity, as well as transmission to enable the development and export of new renewable resources. Because, it appears that Maine and the Eastern Canadian Provinces have similar characteristics and opportunities in terms of diverse resource development, it should be easier to adopt processes and rules that are consistent with these shared goals than it would be in ISO-NE.

c. Cost issues

The supply prices that would prevail under either the Maine ITC or ME/NB Common Market alternative would depend upon how the alternative is ultimately structured, as well as what new resources are developed. Factors that would affect supply prices include: (1) whether prices are cost or market based; (2) market rules; (3) future resources and transmission development; and (4) seams with ISO-NE. If retail access cannot be maintained under either alternative, a ratepayer backed generation vehicle would change generation service pricing from a marginal cost to average cost regime.

recognize that, should that combination prove unreasonably difficult to achieve, the implications for Maine of a combination only with New Brunswick are likely to be closely comparable.

[85] See, e.g. *Atlantic City,* 293 F3d at 11-12.

i. Energy and capacity prices are unlikely to differ from the status quo, unless seams are erected.

Energy prices in Maine currently track below the rest of ISO-NE due to the export constraints discussed in Section IV. This differential is a currently a function of the physical seam created by the supply/demand relationship in Maine and transmission capacity to the south. In either the Maine ITC or the ME/NB alternative, the differential could also be influenced by a financial seam that could exist, e.g. if generators were charged transmission costs to export to ISO-NE.

It might be possible, in theory, to isolate Maine from the New England energy markets in either alternative to ISO-NE. If so, Maine's energy price would depend primarily on the characteristics of the generation within the region, be that region Maine alone, or ME/NB. Assuming isolation could be achieved, it is unclear what prices would prevail. Maine's fleet of generation resources is highly dependent on natural gas. Indeed, Maine has a higher percentage of natural gas electricity generation capacity (49%) than New England taken as a whole (40%).[86] Thus, natural gas would likely continue to be a major driver of energy costs. The combined ME/NB generation fleet has a greater degree of diversity, including oil and nuclear. When combined with Maine's generation fleet, natural gas would be about 20% of total capacity.[87] However, with each alternative to ISO-NE there is uncertainty about what types of generation will be developed and set market prices (or comprise an average price regime).

In any case, for a variety of reasons – not least of which is the improbability of FERC approving any configuration that would have the effect of substantially impeding interstate commerce in electricity by the creation of seams – the development of a Maine or ME/NB structure would not be likely to have a sustained downward impact on the cost of electric energy. As a practical matter, the New England market will still dominate prices. Generators in Maine and New Brunswick would look to New England as the "opportunity cost" of their transactions. Thus, it is unlikely that moving from the *status quo* to the Maine ITC or ME/NB alternative would have any appreciable impact on the cost of electric energy to Maine consumers.

Under the current ISO-NE tariff for the Forward Capacity Market (FCM), Maine may in the near-term pay less for capacity than the region as a whole.[88] Due to the fact that Maine currently has a surplus of generation and existing transmission constraints prevent that capacity from being fully used throughout New England, Maine's capacity auction will stand apart from the rest of New England. Based on current system configurations, then, there, should tend to be a lower price for capacity in Maine than in the rest of New England.

In light of current capacity conditions in Maine and New Brunswick, it is reasonable to conclude that whatever structure is adopted for Maine or ME/NB option, capacity costs would track below the rest of New England in the near term. In the longer

[86] See http://nepga.org/contents/ISO-NE%20-%20ME%20Profile%202-06.pdf
[87] Based on 2006 fuel mix for Maritimes Area and Maine.
[88] See discussion in Section V.A. This depends upon future development of transmission and generation.

term, however, the assessment is more difficult. Moreover, maintaining congestion has certain costs.

Relatively lower capacity prices in Maine may divert investment that would otherwise locate here. While it is likely that new generation investment would remain attractive in Maine and New Brunswick due to the relative ease of siting and abundance of natural resources, if the financial incentives for investment are insufficient relative to other areas in New England, the current surplus in Maine and New Brunswick may diminish. Moreover, the siting of new generation within Maine may be, in part, a function of whether new generation can sell its capacity and energy into the New England market, something that would depend in part on the market rules concerning the seams between Maine and New England and in part on the available transmission capacity. In one sense, moving from the New England market into a Maine ITC or ME/NB combination would be similar to injecting permanent price separation into the capacity market. If such a seam were sustained, it could discourage investment and draw corrective action by the FERC.

ii. Energy and capacity may diverge to an "average" cost regime if retail access cannot be maintained.

Energy prices and capacity prices are formed, in part, by market forces in New England. It is the force of this market that drives price convergence with New England. However, retail competition, and the market upon which it relies, may not be sustainable for all Maine consumers under the Maine ITC or Maine/New Brunswick Options.

Maine's experience with retail competition has been founded on a regional market. As discussed above, from the earliest days of competition in Maine, the Commission recognized that an ISO, complete with a liquid market, is essential for the success of a retail market. Suppliers serving load in Maine draw upon the resources of the ISO-NE administered markets. As evidence of the importance of the ISO-NE managed wholesale power market to retail competition in Maine, the vast majority of the load of large industrial and commercial consumers in Maine participates in the retail market, including several customers with arrangements that enable them to be self-supplied by the ISO-NE managed day-ahead and/or real time markets. In addition, residential and small commercial consumers receive standard offer service that is acquired through a vigorously competitive bidding process. The experience in southern Maine with competition stands in stark contrast to the experience of northern Maine, which is one of obvious failure. Commission interviews with competitive providers offering service in southern Maine who have considered serving northern Maine suggest that lack of liquidity, transmission seams, unique market rules and a relatively small market combine to inhibit market entry.

It is unclear whether Maine, as a stand alone ITC, could support a sufficient market to maintain retail competition. While southern Maine's market is more than ten times the size of northern Maine, we are not aware of another market of this size that has sustained retail competition. While it is conceivable that establishing a market system similar to ISO-NE's and limiting seams could provide sufficient liquidity to support a retail market, the outcome is far from certain. Consequently, if a Maine ITC is formed, a load serving entity of some kind should be considered. The load serving entity could be either a public power agency, or a franchise investor owned utility. In either case, the load serving entity would be obligated to secure sufficient generation capacity to serve Maine consumers. This approach would effectively end retail competition in Maine and terminate Maine's experiment with restructuring. Ending retail competition in Maine poses risks to consumers. Currently risks associated with bad generation investments rests with the private sector, rather than ratepayers. Maine's restructured market place has stimulated over a billion dollars of generation investment in Maine since 1997, and many hundreds of millions are poised to be invested in new renewable generation over the next few years. Although consumers would support this investment through the FCM market, they would not be liable for stranded costs of bad investments.

While in theory it might be possible to continue with retail competition in Maine if Maine utilities withdrew from the New England market and formed an ITC (or, for that matter, a market comprising Maine and one or more Canadian province), Maine's current market structure would be difficult or impossible to sustain in practice. The principal reason is that, unless market rules in the new entity of which Maine becomes a part are perfectly coordinated with, or exactly the same as, the rules in the New England market, there will be a "seam" between the markets that sellers and buyers may find too much trouble to overcome for the benefit of Maine's relatively small customer loads. In the absence of full access to the resources throughout New England, the Maine market (or even a market that combines Maine and Maritimes sellers) would be unlikely to provide the kind of robust competition essential for Maine's current retail market. Thus, as a practical matter, adopting either the ITC or Maine/Canada structures as an alternative to the current participation in the New England market would likely require moving to more regulated generation and an average pricing regime.

There are, of course, reasons to consider moving towards a more regulated generation and average (rather than marginal) cost regime that apply under any approach to regional participation, i.e. even if Maine remains a part of the New England market. As articulated elsewhere in this report, one of the characteristics of the current market is that the clearing price is dominated by the cost of natural gas, which in turn is marked by a high degree of volatility and historically high levels. One response for Maine would be to return to an average price regime for Maine's retail consumers, in effect combining the market price for energy available in the market with a regulated price for energy produced by regulated generation. Because regulators could influence more directly the type of generation being built, this approach would provide an opportunity to reduce the relative importance of natural gas in the price and, at the same time, increase the use of renewable or other RGGI- friendly generation.

iii. Transmission costs (including the implications of socialization or beneficiary assignment)

In the Interim Report, we found that the projected transmission costs of a Maine ITC or a combined ME/NB system would, on average be below the projected costs to Maine consumers of remaining within the ISO-NE transmission tariff. This conclusion was driven by two principal projections: that the share of regional costs borne by Maine for transmission outside of Maine would continue to grow more quickly than the cost of transmission within Maine (i.e. Maine "imported" costs were viewed as likely to exceed Maine's "exported" costs), and the expectation that the Maritimes provinces would not be developing major new transmission in the near future.

Developments during 2007 suggest that these assumptions, and the tentative conclusion concerning the transmission cost element of the comparison between the *status quo* and a new configuration, be reassessed. In particular, there are likely to be proposals for new transmission in Maine that might, depending on the extent of additional construction elsewhere in NE and the projects ultimately approved in Maine, alter the direction of the impacts of cost socialization as currently applied under the ISO-NE system. The first of these proposals, relating to extensive upgrades of the CMP transmission system between now and 2017 (characterized in public as the Maine Power Reliability Program), has been described as requiring over $500 million in new investment. The second, involving the possibility of connecting the MPS system directly to the New England system (described as the Maine Power Connection) currently has no defined scope or cost estimate; in the event, however, that the proposal ultimately encompasses a major facility reaching into New Brunswick, as might be the case if the objective is to increase flows from the resources in New Brunswick, Quebec and Newfoundland & Labrador into Maine and the rest of New England, the costs could be substantial.

In the short term, continued participation in ISO-NE could allow more then 90% of the costs of these projects to be borne by customers outside of Maine. Put another way, to the extent that Maine, through its regulatory process, found benefits of increased internal reliability, and increased flows through and out of Maine to New England, those benefits would be achieved at a fraction of the cost that would be incurred by Maine consumers if Maine stood alone in its transmission tariff or joined with its Maritimes neighbors.

The evaluation of the financial impact on Maine consumers of withdrawing from the New England tariff and joining with New Brunswick and perhaps other Maritimes provinces would thus be a function of at least three variables: the costs that would be borne by Maine as a result of its roughly 8% share of the socialized costs of major projects elsewhere in New England; the costs that Maine would be able to export under the same tariff for projects within Maine (approximately 92% of projects approved for construction); and the extent to which costs in the Maritimes and Maine would be shared. (See Appendix A for an analysis of these variables.) On the last point, it may be unrealistic to assume that Maine's costs in a combination with one or more Maritime province would be less than costs would be under a stand-alone tariff: those provinces would be unlikely to agree to a socialization approach that increased their own costs. The analysis provided in Appendix A provides a range of possible scenarios to evaluate transmission cost impacts.

On balance, however, the continued pressure in southern New England for transmission, and the relatively higher cost of that transmission when compared to Maine, suggests that even if Maine had to bear its own costs and proceeded with all of the transmission projects that might be needed to ensure reliability and the ability of new generation to reach the southern New England market, Maine's costs for transmission are likely to be lower under either the Maine ITC or ME/NB Options than the *status quo.*

iv. *Voltage regulation (and other ancillary services) and reserves can be procured cost-effectively under either alternative.*

The Interim Report concluded that, under either alternative to ISO-NE, both voltage regulation and reserves could be provided with sufficient reliability at a reasonable price when compared to the costs currently incurred by Maine customers within the New England market. To some extent this conclusion depends on the terms under which regulation and reserves are provided by generators in the relevant region, something that would need to be developed in the context of the market structure discussions for either alternative. However, using the plausible assumption that, in the absence of genuinely competitive regulation and reserves markets (and there is reason to believe that the markets in these areas would not be workably competitive due in part to the ownership structure for generation in Maine and the Provinces) the prices would be based on cost (as they are now in the NMISA). Thus, the price difference between obtaining these services for Maine alone, or in a ME/NB combination, and obtaining them in the New England market is unlikely to be large enough to suggest that this element should guide the decision concerning what structure is best for Maine.

v. *Reliability can be maintained under either structure – but wind development may be constrained.*

With the two caveats noted below, moving from participation in ISO-NE to either alternative is unlikely to have a material impact on the reliable production and delivery of electricity within Maine. As the Interim Report indicates, there appears to be adequate generation to meet projected load in Maine and, assuming the Point LePreau nuclear reactor is refurbished on time (2010), in the ME/NB area. Moreover, additional generation in the region has either been announced or is under consideration.

The introduction of significant new wind generation in Maine and within the Maritime Provinces, however, raises an issue concerning the ability of the system to absorb a significant amount of intermittent resources. The NBSO has indicated that it believes its system can absorb on the order of 200-300 additional MW of wind generation without creating operational issues. While the issue of how much wind capacity can be absorbed into a system of any given size remains controversial to a degree, there is some indication that, where wind capacity substantially exceeds 10% of the system within which it is dispatched, operational reliability may be compromised. In light of announced plans for in excess of over 1000 MW of new wind capacity in Maine alone, and the indications from New Brunswick and Prince Edward Island that each is seeking to install an additional 200-400 MW of wind generation, the possibility exists that a system with dispatch control only over Maine (3,200 MW of capacity), or ME/NB (6,500 -7,000 MW of capacity**)** area would have difficulty absorbing all of the wind projects now contemplated.

A second reliability issue, the significance of which is necessarily more difficult to assess, is that larger systems by their nature provide a more robust "view" of the real time operation of the system and therefore may, all else being equal, provide better system reliability. This point has been articulated by the RTO/ISO Council:

> ISO/RTOs' scale of operations allows them to see a broader picture of grid conditions than the typical, smaller, stand-alone grid operator. Because of their "big picture" view, they are better positioned to detect developing problems on the grid. Because of their scope and sophistication, they have increased flexibility to respond to the situations they detect. In the even of a system emergency, the ISO/RTO is the central authority within its footprint, determining what actions transmission and generation owners should take to protect the grid.[89]

Notwithstanding the RTO/ISO Council's clear self-interest in promoting the value of larger systems, the argument that a higher number of data points across a broader area will yield better information about the state of the network seems intuitively obvious. The question, of course, is whether the difference between a system the size of New England, and a system on the order or 8% to 20% of its size, is enough to warrant choosing one structure over the other. On balance it appears that the superior reliability of greater size, if it exists, is unlikely to be different enough to justify this factor as an important element in the decision concerning which system is best for Maine. This conclusion is buttressed by the reliability requirements of new federal energy law, which mandate conformity with a wide variety of reliability standards.[90] There is no reason to believe that the reliability functions now performed by New England for Maine as part of its participation in ISO-NE could not be performed for Maine by a new entity, or even by ISO-NE under contract, in the event Maine moved to a different system configuration.

vi. Administrative costs will vary depending upon the expectations of market participants.

The costs attributable to RTOs and ISOs have recently come under considerable scrutiny, with defenders of RTOs pointing to the market and reliability benefits, and the costs displaced from utilities, and detractors pointing to what appeared to be a pattern of increase in costs even when measured by cost per unit of output (e.g. per MWh).[91]

For the purposes of this analysis, however, one important question is the scope of function of any entity that would replace the role of ISO-NE. Both the NMISA and the NBSO perform some, but not all, of the market and operational functions now performed for most of Maine by ISO-NE; the costs per/MWh costs for those operations are in the range of $0.30 MWh and $0.25/MWh, respectively.[92] As discussed below, either a Maine ITC or a ME/NB organization would most likely have market functions less complex (and less expensive) than the markets operated by ISO-NE or the other major RTOs; for that reason, it is likely that the administrative costs under either alternative would more closely resemble the costs of NBSO and NMISA than ISO-NE. On the other hand, there are transmission planning requirements articulated by the FERC which would need to be performed by the Maine utilities at least (and perhaps also by any entity of which the Maine utilities are a part); there may be

[89] From "The Value of Independent Regional Grid Operators," ISO/RTO Council, November 2005, at p. 11.
[90] *See* Energy Policy Act of 2005 § 1211.
[91] See e.g., "The Value of Independent Regional Grid Operators," ISO/RTO Council, November, 2005; "The Costs of Participating in Restructured Wholesale Markets," an American Public Power Association presentation, Bateman & Smith, February 5, 2007.
[92] The comparable cost for ISO-NE is in the range of $0.80/MWh

modest efficiencies available in a larger entity (such as ISO-NE) performing these functions. It is not obvious, however, that this difference – on the order of $0.50 /MWh (or about $3.50 per year for the average residential customer) -- is large enough to warrant significant weight in the determination of whether Maine should move forward with an alternative to ISO-NE.

Under either alternative, therefore, there are common elements that distinguish those alternatives to ISO-NE. However, the Maine ITC Option and the ME/NB Common Market Option each have unique characteristics that may affect their respective ability to achieve the region's fuel diversity and environmental goals in relation to the *status quo*.

2. Maine ITC Option: an independent transmission company and state-wide load serving entity

The Interim Report identified an Independent Transmission Company (ITC) as a possible alternative to the current ISO-NE arrangement, especially if CMP and BHE decided to withdraw from ISO-NE prior to the end of the initial term of the TOA. Specifically, the Interim Report stated:

> Of the circumstances giving rise to the potential for early withdrawal, the formation of an ITC[93] is the most pragmatic for CMP and BHE, if early withdrawal is desirable. FERC's approval is required to form an ITC[94] and for early withdrawal. In most respects, if early termination is permissible and acceptable to FERC, the obligations on the withdrawing utilities are the same as they would be under withdrawal at the termination of the TOA. As discussed above, a transmission organization replacing an RTO, like an ITC, should also meet all of the requirements of a replacement organization outlined in *Louisville*, including the filing of an Order 888 compliant tariff. Finally, the same legal analysis applies to exit fees under an early withdrawal as a withdrawal after the initial term.

Here, we reaffirm the viability of a Maine ITC as an option to ISO-NE for consideration.

A properly formed ITC could be superior to the *status quo* in meeting Maine's and the region's fuel diversity and environmental policies. An ITC would avoid the impact of regional socialization inequities on Maine consumers, and, thereby, potentially lower consumer costs. Moreover, an ITC could undertake some, if not all, of the transmission planning and development operations currently performed by ISO-NE to ensure that Maine's and the region's environmental priorities are met by resources from Maine and Eastern Canada. Perhaps the greatest advantage of an ITC would be the return of important electricity policy and implementation decision-making to companies and agencies that are more accountable to Maine consumers.

[93] An ITC is a for-profit transmission company that meets the independence criteria of Order 2000. An ITC may operate within an RTO, as contemplated in the TOA, or instead of an RTO.
[94] *See*, ISO-NE OATT, Attachment M.

However, upon further analysis we believe that an ITC alone will not be sufficient to maintain a safe and reliable electricity system in Maine. We believe that a load serving entity is likely to also be required to serve the majority of Maine consumer's generation needs, such as a public power authority or an investor-owned franchised utility in the fashion of Maine's pre-restructuring electric utilities. Consequently, this alternative could effectively end Maine's experience with retail competition, at least for small business and residential customers. By ending retail competition, Maine consumers could benefit from rate-based utility generation ownership, but would be exposed to the risks of building new power plants that are now shouldered by private firms.

a. *Early Withdrawal from ISO-NE*

Since the Interim Report was filed with the Legislature in early 2007, the Commission has continued its exploration of the potential for early withdrawal from ISO-NE, by means of the formation of an ITC. Accordingly, the MPUC staff requested comments from interested persons on issues relating to the formation of an ITC. In response to the Request for Comments,[95] CMP, BHE, IEPM, and the IECG filed comments on various questions related to ITC formation and transmission cost allocation.

CMP and BHE both responded generally that early withdrawal through the formation of an ITC posed significant challenges. BHE stated:

> The most significant disadvantage of formation of the ITC as a vehicle to early withdrawal from ISO-NE is that formation of an ITC will likely be an arduous process at FERC given that the degree to which FERC will allow active control of the ITC by market participants unknown. The process will involve numerous intervenors, and will likely by hard fought, costly and time consuming. BHE believes that those resources may be better spent focused on the negotiations which will come near the natural termination date of the existing operating agreements.[96]

CMP stated:

> Other than allowing for earlier withdrawal from ISO-NE, the primary advantage of an ITC would be to create a single purpose entity whose sole focus and resources are dedicated to transmission reliability and reducing supply prices by reducing transmission congestion costs. At this time, such an advantage may not outweigh the start up costs and effort required to form an ITC especially considering that currently CMP has effective transmission operations and favorable access to capital.[97]

[95] This request for comments and related documents can be found at Commission's electronic case file at http://mpuc.informe.org/easyfile/easyweb.php?func=easyweb_splashpage, Docket 2006-364.
[96] Docket 2006-364, BHE Response No. 8.
[97] Docket 2006-364, CMP Comments at 5.

We believe that CMP and BHE's resistance to vigorously exploring an ITC as a vehicle to early withdrawal is reasonable. Nonetheless, an ITC formed after the natural termination of the existing agreements could be a vehicle to replace many of the functions of the existing ISO-NE. Among the key functions of the ITC for which ISO-NE is now responsible are:

- Independent transmission tariff administration;
- Independent transmission system operation;
- Generator control and dispatch;
- Generator interconnection; and
- Transmission system planning and expansion.

Formation of a Maine ITC could be complex, however, and involve significant transaction costs. The ISO-NE transmission owners' agreement, which vests authority over these issues in ISO-NE, took years to negotiate and was the subject of vigorous stakeholder scrutiny and litigation. Furthermore, regulatory approvals will be significant. The formation of an ITC would require numerous regulatory approvals and transactions. A list of the transactions and approvals identified by CMP and BHE follows:

- Corporate formation agreements

- Approvals by the MPUC of (1) authority to serve as public utility, (2) reorganization, (3) transfer of assets, (4) affiliated arrangements and (5) financing,

- Approval by the FERC of (1) rates and conditions of service over transmission facilities used in interstate commerce, consistent with the requirements of Orders 888, 889, and 890 and Standards of Conduct (Order No. 2004),[3] and (2) transfer of assets, approval of the TOA,

- Service agreements between the forming utility and the ITC.

- Separation of the financial records of the business between the transmission and distribution utility and the ITC as well as a restructuring of its accounting structure to provide for separate financial statements, internal accounting systems, forecasts and budgeting, and

- Bills of sale, deeds, easements and leases to transfer the assets from the transmission and distribution utility to the ITC.

Maine's transmission owners suggest that establishing a new organization intending to serve these functions will similarly consume months if not years of negotiation, stakeholder process and litigation. We agree. In terms of start-up costs, CMP estimated costs that "could range from $1 million to $10 million for such services as legal, tax, business planning, communications, government affairs, public relations, executive services, and transmission planning and operations."[98] This estimate did not include costs associated with the transfer of assets or the tax implications of such transfers, which CMP opined could be significant. BHE stated:

> Costs associated with formation of an ITC include legal costs and filing fees associated with the many regulatory approvals ….Further, if the utility is reorganizing and transferring its existing transmission assets to an ITC, there will be costs associated with restructuring existing financing. There will also be internal costs at the utility level associated with resources dedicated to formation of the ITC (finance and accounting staff, project management, legal and regulatory staff, etc). [99]

In summary, although early withdrawal by the utilities from the Transmission Owners' Agreement is not practical, between now and 2010, when the existing ISO-NE agreements are set to expire, there may be sufficient time to manage the contractual and regulatory commitments required to form an ITC. The cost of doing so, however, could be substantial. [100]

b. *Withdrawal from ISO-NE at the expiration of the existing ISO-NE agreements*

The formation of an ITC as a means of withdrawal from ISO-NE raises direct and ancillary policy issues. The most compelling incentive for Maine to choose this alternative is that it would return to Maine major decision-making capacity that has drifted to ISO-NE and the FERC over the past decade. In addition, the formation of an ITC will also enable Maine transmission owners, in a coordinated fashion, to plan and develop transmission needed to increase exports from Maine to the region to aid state and regional policy goals. An ITC will also directly impact, transmission cost allocation, transmission expansion financing, seams management between Maine and New England, capacity costs, energy costs and private investment in Maine's generation sector. Indirectly, the formation of an ITC implicates retail electricity market restructuring in Maine, as well as interregional coordination.

i. *An ITC would center decision-making about Maine electricity policy in Maine.*

FERC maintains exclusive jurisdiction over electricity transmission. Transmission finance, rates and a utility's rate of return are all subject to regulation by FERC.[101] Pursuant to the Energy Policy Act of 2005, in certain circumstances the federal government may also assert jurisdiction over transmission siting.[102] Although an ITC

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[98] Docket 2006-364, CMP Comments at 3

[99] Docket 2006-364, BHE Response No. 3.

[100] However, it is worth noting that capacity costs pursuant to the FCM that Maine consumers will pay over and above those that the Commission believes are just and reasonable will exceed $128 million by 2010 – more than 10 time CMP's estimates of transition costs to move toward an ITC.

[101] Under the Federal Power Act ("FPA"), FERC has exclusive jurisdiction over "transmission of electric energy in interstate commerce."[101] The Supreme Court has held that "transmissions on the interconnected national grids constitute transmissions in interstate commerce." *New York v. FERC*. 535 U.S. 1 (2002) citing, *FPC* v. *Florida Power & Light Co.,* 404 U. S. 453, 466-467 (1972); n. 5.

[102] *See,* Energy Policy Act of 2005 § 1221, 16 U.S.C. § 216(a).

would, similar to ISO-NE, be subject to vigorous FERC regulation, a less regional scope would presumably tend to orient decision-making toward Maine concerns. Utilities with state jurisdictional distribution assets are also more likely to be responsive to state concerns and those of its consumers than an entity based in another state regulated exclusive by a federal agency and accountable to a region of which Maine is only a part.

The disaggregation of Maine's utilities from regional bodies will tend to bring greater local, public accountability to the transmission management apparatus, which is currently lacking. This is, perhaps, the greatest benefit of an ITC, and a clear advantage over the *status quo*.

ii. The ITC will enable coordinated transmission planning and development consistent with state and regional policy goals.

Maine transmission owners currently pursue transmission expansion studies through the ISO-NE process independently of each other. There is insufficient coordination or cooperation in this process, nor is there explicit consideration of transmission needs in light of generation adequacy, diversity or other state or regional policies. At this time there are four major transmission expansion proposals in Maine: the Maine Power Reliability Project (CMP); the Maine Power Connection (CMP/MPS); the Green Line (an independent transmission company); and a DC interconnection being proposed form Orrington, Maine to a terminus in Massachusetts (BHE). These projects appear to be in the process of study in an uncoordinated, and potentially inconsistent, manner. Nowhere has a strategic and coordinated effort taken place to identify specific transmission goals for Maine, or the exports from this state that transmission could facilitate.

There is no regional or local apparatus to identify transmission that may be needed to facilitate generation exports from Maine, or through Maine, to southern New England. Without such an assessment, potential transmission investors, including independent investors like the Green Line, face regulatory uncertainty. Furthermore, there is no regional policy vehicle to determine whether these four projects, a subset of the projects, or more projects are required to support enough generation for the region to meet its public policy goals. A single ITC for Maine could coordinate the way transmission projects are planned for Maine. Thus, in these respects, a Maine ITC is superior to the *status quo*.

iii. The formation of an ITC will directly affect transmission cost recovery and allocation, and could create seams.

In conjunction with a Maine ITC, a single Maine-wide transmission tariff could be formed. Currently, how consumers are charged, and which consumers are charged, varies greatly by the approach used to recover transmission costs. In New England, the region recovers costs related to pool transmission facilities (PTF) through a regional tariff offering regional network service (RNS) to customers. Customers in the region are allocated costs depending upon their share of the total use of the system at the monthly network peak. Generators interconnected to the PTF system do not pay for transmission service beyond what is necessary to interconnect to the PTF transmission system. However, generators seeking to serve customers outside of New England in New Brunswick must pay "out service" charges to wheel out of the RTO.

Not all transmission in New England is PTF. Indeed, Maine utilities have substantial amounts of "non-PTF" transmission (typically lower voltage and/or radial compared to PTF). Because the existing tariff determines that non-PTF transmission supports local needs rather than the regional bulk power system, its costs are recovered from local ratepayers rather than regional customers taking RNS service. Generators interconnected to certain utility's non-PTF systems, such as BHE's, must also pay these local charges to wheel to the PTF to serve customers outside of the utility's service area.

With the formation of an ITC, a single uniform tariff for Maine is conceivable. The ITC would reconcile (consistent with regulatory approvals) whether generators in Maine should be required to pay out-service. There is sound public policy that supports that users of the transmission system ought not to be relieved of the burden of paying a fair share of system costs. Out-service achieves this for generators serving non-native load. Such out-service is often referred to as a "seam."

iv. Seams and instability must be managed so as to minimize chilling generator investment.

The term "seam" is used to describe variations in transmission and market systems. Seams are a fact of life in electricity markets and are tolerated more often than they are removed. Seams are often the reflection of legitimate cost-recovery schemes, like out-service charges from non-PTF transmission. Nevertheless, seams create distortions in electricity markets and can chill investment. The Canadian Electricity Association defines seams "as inefficiencies that prevent the economic transfer of capacity and energy between neighboring wholesale electricity markets, or between control areas, largely as a result of incompatible market rules or designs."[103] If Maine forms an ITC, generator investment could be chilled by out-service charges or market rules that differ greatly from ISO-NE's. If this occurs to a degree, then the ITC will not achieve the policy ambitions of the region to substantially expand access to non-CO_2 producing generation. It is even possible that seams between Maine and southern New England could skew generation investments decisions in Maine and New Brunswick to such a degree that the ITC could be less advantageous than the *status quo*.

In addition, there could also be costs associated with an uncertain investment climate. Maine has been the site of enormous private investment since restructuring's dawn in 1997. Independent power producers are currently anticipating spending hundreds of millions, if not billions of dollars in Maine on generation development in the coming years. Moreover, there is more than $2 billion of transmission development on the drawing board for Maine. This type of investment, in transmission in particular, is likely to be chilled by risk associated with a change in the regulatory paradigm. Even though the Maine ITC Option

[103] A Discussion Paper On Electricity Seams, Prepared by the Power Marketers' Council and the Transmission Council of the Canadian Electricity Association (CEA), June 2006. http://www.canelect.ca/en/Pdfs/SEAMS-En_Rev1_Sept7.pdf

could be superior to the *status quo* in a reasonably projected end-state, investment risk would exist in the interim.

v. *The financial capability of Maine's utilities standing alone will not be as robust as the region's transmission owners in combination – potentially limiting transmission investment.*

While an ITC could lower costs for consumers and rationalize transmission planning, it is possible that transmission financing would be more limited under this scenario than the *status quo*. Maine represents 8% of the region's consumers. Thus, Maine's utilities represent a small fraction of the entirety of the region's transmission owners. If the region focused its resources on developing transmission in Maine it is likely that more transmission could be financed here than if Maine were to stand alone. (One vehicle to assist in managing costs could be to charge out-service from generators to finance the transmission system that they will use to export resources from Maine. However, this would introduce the seam-related risks described above.)

3. Maine/New Brunswick common market

All of the considerations described under the Maine ITC Option are relevant to the ME/NB Common Market Option to some degree. Advantages include greater self-determination, rationalization of tariff structures and transmission planning and development, and potentially lower consumer costs. A load serving entity, such as an investor owned utility or public power authority, may also be required for the same reasons. It will be difficult to maintain retail competition, at least until a common market is well established.

a. International context is not an obstacle.

An international boundary is not a compelling barrier when compared to the *status quo*. Today, none of the relevant regulatory authorities or sovereign governments – FERC, the Maine PUC, the Maine legislature, or any Canadian governmental interests – has any inclination, or practical ability, to relinquish its authority over the entities that now form ISO-NE or would comprise a ME/NB common market. It might appear at first blush that moving to a ME/NB configuration, where the conduct of the New Brunswick or other Maritimes entities would not be subject (except perhaps through the enforcement of contract law) to any Maine or U.S. jurisdiction at all, would diminish Maine's influence over important elements of its electricity market. In practice, however, there may be little difference. Neither New Brunswick nor any of the other Provinces is likely to give up its authority to ensure the maximum benefits for its customers, so ME/NB would not provide a structure where Maine's interests would be advanced unless the other participants perceived those interests to be consistent with their own.

In light of the understandable reluctance of either Maine or the Maritimes provinces to defer to the jurisdiction of the other with respect to authority over a ME/NB market, the most likely structure for ME/NB would be a series of contractual arrangements among the market participants along the lines of the relationships among MISO, the market participants in MISO, and Manitoba Hydro. These provide a clearly specified area within which coordination is expected, provide for cost sharing and common dispatch, and identify the areas where local determination remains paramount. Ultimately, however, these relationships depend on the ability of the contracting parties to enforce their contracts in the courts of the respective jurisdictions, and not (as in the case of the United States RTOs) on regulatory authority over tariffs.

The essential point with respect to jurisdiction is that shifting from ISO-NE to ME/NB would be neither a blessing nor a curse. Maine has little influence today, and thus has little to lose by leaving the ISO-NE market; but the reasonable self-interest of the Maritimes provinces, and their independent sovereignty, prevents any assumption that Maine's influence would be greater as a part of a ME/NB market. In both cases, Maine would retain the authority it has over its internal retail market, and over the procurement and supply issues for its citizens should it choose to exercise that authority; but in neither case can Maine count on influencing those with authority over a broader market to Maine's unilateral advantage.

None of this is to say that there may not be extensive common interests between Maine and other parties to a ME/NB structure, or that a formal ME/NB structure might not provide a useful vehicle for advancing those common interests. The point is only that moving from ISO-NE to ME/NB would not materially increase the structural or formal ability of Maine to influence the conduct or characteristics of the markets beyond its borders.

b. Common market structure not likely to provide substantial liquidity.

As the Interim Report observes, a market comprising only Maine and the Maritimes provinces would have significant concentrations of generation ownership. For that reason, absent significant structural change, it seems unlikely that the bid-based clearing price market in operation in ISO-NE and in other large RTOs could be implemented successfully. In effect, the ME/NB area would likely persistently fail the market power screens that, in competitive markets, trigger the obligation to limit bids to cost. Thus, as a practical matter, a ME/NB market would be a market where dispatch is based on marginal cost rather than bids.

Moving back to a cost-based dispatch would not be a simple exercise. The generators in Maine, for example, unlike the generation owned by vertically integrated utilities in the NEPOOL days, are not subject to the full set of regulatory accounting requirements, thus making audit of cost information problematic at least. Adding further complexity is the issue of whether the uniform clearing price approach (i.e. every generator clearing the market is paid the marginal price) should be replaced. If costs are used to set the price, then a "pay as bid" approach would fail to provide sufficient revenues to generators to pay their capital costs, necessitating, at the very least, a market or other mechanism to pay for capacity. A return to the "shared savings" approach of the old NEPOOL structure would be impractical where, as is the case for all Maine generation, there is no regulatory pricing mechanism to ensure both appropriate compensation and proper allocation among generation interests.

Without substantial realignment of ownership throughout the ME/NB region, including fragmentation of ownership of generation within the Province and sufficient transmission capacity to minimize or eliminate congestion, the difficulty in achieving a workably competitive clearing price bid based market in ME/NB might require a re-examination of the entire structure of the electricity market in Maine. Putting aside the daunting transitional issues, the most logical outcome might be a system of regulated generation throughout ME/NB, with cost-based dispatch and shared savings to serve native customers,[104] coupled with average cost pricing.

c. *A common Maine/NB Market would require key elements to promote private investment for export in a fashion to surpass the status quo.*

While native Maine/New Brunswick load will most likely be served by a rate-base franchise entity of some form, exports driven by private sector investment will serve Maine and the region. In order for regulatory structures to earn the confidence of private investment, governments must make their policy choices known, and then maintain discipline through implementation. The experience in electric utility restructuring in the U.S. could inform the development of this alternative, particularly with respect to key issues that Maine and New Brunswick must confront. Experience in the U.S. suggests that private investment in generation has tended to follow regulatory policies that level-the-playing field between legacy investor-owned-utilities and entrepreneurs. The policies vary, but the essential elements of a structure that promotes investment appear to be as follow:

- Security Constrained Economic Dispatch: Generation facilities must only be permitted to run if they are the least cost resource for the dispatch period or needed for reliability.

- Open Access Transmission: All transmission capacity must be available to all parties on non-discriminatory terms.

- Independent Transmission System Administration: The transmission system must be operated by a body independent of any market participant. Actual self dealing, or the possibility of self-dealing, by utilities in the interconnection of new resources or the operation of the transmission system is particularly disconcerting to private investors.

- Market System Coordination with Liquid Markets: Access to the New England market is essential for private investment. Coordinating market rules and interregional transmission planning enhances market access.

In addition to these essential items, an open and transparent transmission planning process, and the divestiture of “dispatchable” generation by a utility tends to improve investor confidence. However, these elements tend to be less important that those enumerated above.

[104] Private sector investment for export could be maintained with the market reforms described below.

VI. CONCLUSION

This Final Report, together with the Interim Report delivered to the Legislature on January 16, 2007, represents the Commission's analysis of the *status quo* regulatory regime in New England and alternatives that may better meet the policy goals of Maine and the region. The Commission believes that the *status quo* is fundamentally flawed. The three options to the *status quo* that we outline will each, in varying degrees, be superior to the current regime.

However, each policy option is complex and requires careful consideration by the Legislature. Ultimately, the Legislature must weigh whether the infirmities of the *status quo* are so great that the risk of regulatory change is warranted.

Appendix A
ISO-NE Cost Analysis

This appendix is an update to a similar analysis that was part of the Interim Report to the Legislature. The primary updates reflect several new proposals for additional transmission investment, both in Maine and in other parts of New England, and corrects an error in the calculation of the impact of transmission investments on electric rates contained in the Interim Report.

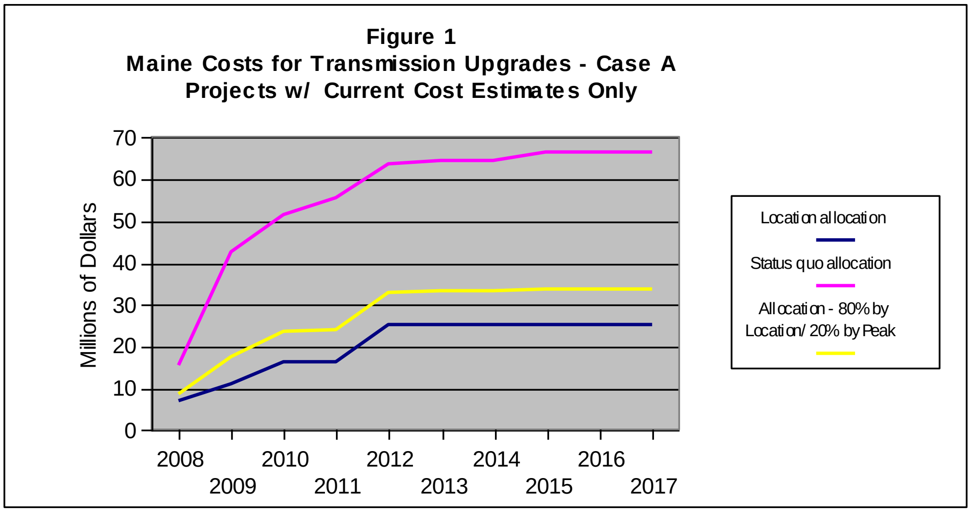
Two findings from this Appendix merit highlighting here. First, we estimate that the costs of remaining part of ISO-NE for the five years from 2008 to 2012 will be approximately $500 million, somewhat less than the $616 million estimate from the Interim Report. Second, the Appendix highlights the interaction between the level of transmission investment and the impact of allocating transmission costs in different ways among the New England states. For example, if transmission investments in Maine are relatively low, as they were projected to be at the time of the Interim Report, then Maine would fare best under a hybrid "beneficiaries pay" methodology. On the other hand, if transmission investments in Maine are high, relative to the other states, Maine's costs would be slightly lower if upgrade costs were "socialized" or recovered based on peak usage, than under a hybrid "beneficiaries pay" model.

1. Transmission

Many of the costs of the transmission system are "socialized" by the RTO. Under the current cost allocation methodology, Maine pays into a transmission fund based on the average cost of all New England transmission but receives revenue from the fund based on the cost of the transmission located within Maine. As a result, if there is proportionately more transmission investment outside of Maine, or in Maine to benefit customers to our south,[105] Maine's net cost will increase because the New England-wide costs would be growing faster than the costs necessary to serve Maine customers.

The ISO estimates that the net cost of socialized transmission will increase in the future. There are major new transmission projects elsewhere in New England that are either under construction or being designed that could cost from $8 billion to $16 billion between 2008 and 2017. These projects can be divided into three categories. First, there are projects where cost estimates currently exist, although the true costs may differ from the estimates. ISO-NE currently estimates for these projects will cost approximately $4.2 billion between 2008 and 2017.[106] Our first scenario, Case A, considers only those projects for which current cost estimates exist. The effects of Case A transmission investments on Maine consumers, by year, is summarized in Figure 1.

[105] We recognize that since Maine has historically been a net exporter of energy, one could argue that much of the existing transmission in Maine is for the benefit of those to our south.
[106] See October 2007 RSP Update.



As Figure 1 indicates, in this scenario, Maine is better off if costs are assigned by location or if a hybrid model is used.[107] The major reason is that there are few transmission investments in Maine under Case A, so, in effect, Maine consumers are paying a disproportionate share of regional costs under the current socialization regime.

Next, there are a group of projects which are currently part of the plan and/or under active development but for which no formal ISO-NE cost estimate exists. For these projects, we have developed rough estimates of what we expect these projects might cost. The largest transmission project here is NEEWS (the New England East West Solution) which includes a number of upgrades in Connecticut, Massachusetts, and Rhode Island. We estimate that the NEEWS upgrades will cost in the range of about $1.4 billion to $2.5 billion. Another large project is a major upgrade of the CMP network, referred to as the Maine Power Reliability Project (MPRP). Including a few other minor projects, these Maine transmission upgrades could cost in the range of $0.6 billion to $1.7 billion. A third project significant to Maine is a direct interconnection between Northern Maine and the New England Grid. Here we have used estimates of $200 to $500 million as the cost for such a project, but caution that all these estimates are rough. Finally, there will undoubtedly be other transmission investments in New England during between 2008 and 2017. Based on past history, we expect these investments to total another $2.4 to $7.5 billion, but note that the lower figure would only be accurate if the pace of transmission investments is significantly slower than in the past several years.

Our second scenario, Case B, includes all of the projects listed in ISO-NE RSP07. This includes NEEWS, the Maine Power Reliability Project and a new tie to Northern Maine. Figure 2, below, summarizes the results of Case B, under a range of assumptions about the possible costs of new transmission in Maine and the rest of New England.

[107] While a "beneficiaries pay" methodology would be based on a more sophisticated metric than location, we have used location as a beneficiary determinant in this figure solely for illustrative purposes and because of the obvious impracticality of performing load-flow or other detailed analyses for each of the projects in the RSP for the purpose of this report. Because location is a very imprecise indicator of beneficiary however, it is likely that the actual allocations under a "beneficiaries pay" methodology would vary from the estimates in Figure 1.

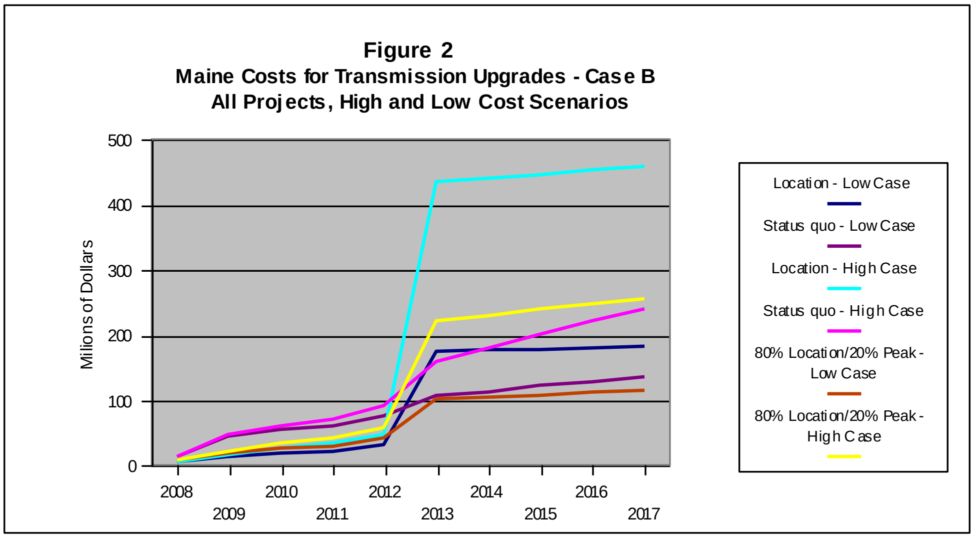
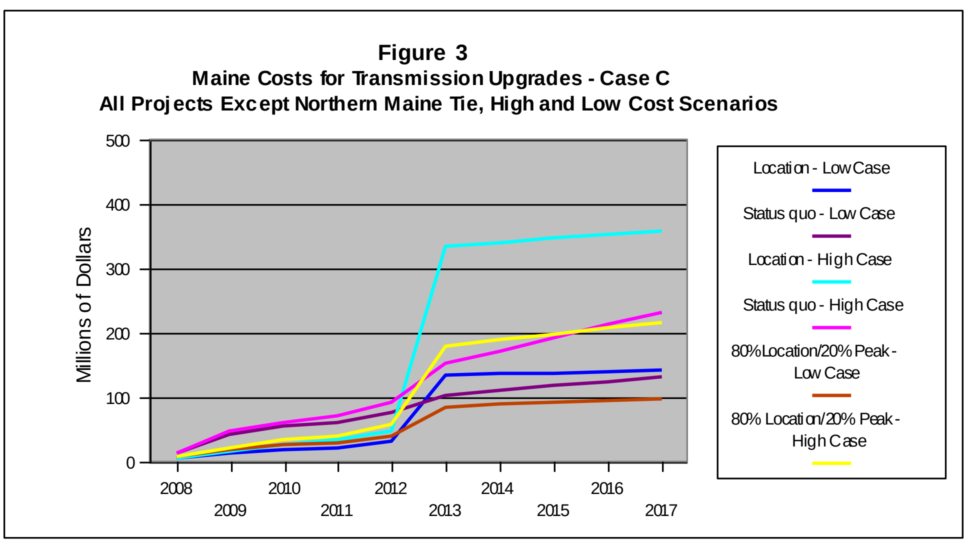


Figure 2 shows that with transmission projects to be built in Maine, under a low-cost scenario, Maine in the long-run would fare best under the hybrid model, followed closely by the *status quo,* socialization model. If costs were at the high end of the range, the *status quo* produces the lowest cost, followed by the hybrid model.

Our final Scenario, Case C, is similar to Case B except that we exclude the tie line to Northern Maine. Comparing Cases C and B allows focusing directly on the cost implication a new tie to Northern Maine

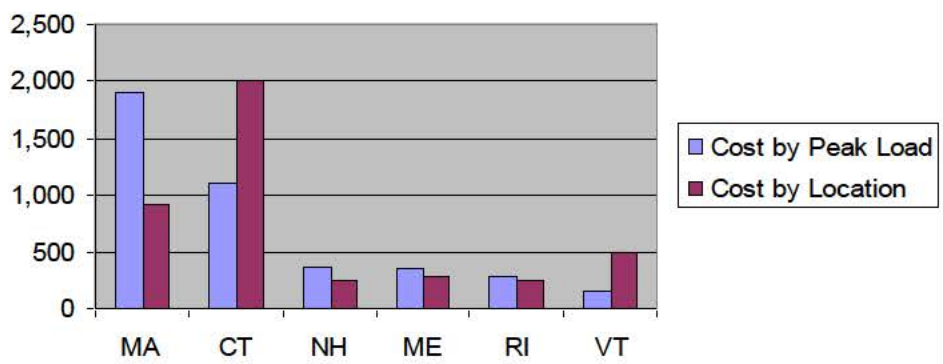


Taken together, these two cases indicate that the cost to Mainers of a new Northern Maine tie are very low under the *status quo* or under a hybrid model, but not if they are based on location.

The discussion above focuses on the cost impacts of new investment. Current rates also reflect the impact of prior investments. For the most recent period beginning June 1, 2007, new transmission in other states caused CMP's payment into the pool to rise by \$8.0 million to \$39.7 million. On the other hand, because CMP did not have as much new investment itself, its receipts from the pool declined by \$3.1 million to \$25.4 million. In other words, CMP's net cost of socialized transmission is \$14.3 million for the current year. For BHE, the net cost of socialized transmission reflected in rates is currently \$1.8 million, so the effect of the current cost allocation approach is to increase Maine rates by about \$16 million annually.

So far we have looked at the impact of cost allocation solely on Maine, but, like any cost allocation question, if Maine pays less, it means that someone else pays more (and *vice versa*). Figure 4 shows the amount of transmission investment assigned to each state for Case A defined above.[108]

Figure 4
Case A - Transmission Investment Allocation
(Millions of Dollars)



2. Administrative Costs

RTO administrative costs are primarily composed of three items: salaries and benefits (40%) depreciation and amortization (30%), and outside consultants and lawyers (20%). The RTO administrative costs are borne solely by customers. In 2005, Maine paid about \$7.85 million as its share of RTO administrative costs and this figure is likely to rise over time.

[108] The results from a hybrid model cost allocation are not illustrated in Figure 4. Further, Figure 4 does not include Maine projects or projects outside of Maine that are in the initial planning stages.

Table 1
Maine's Share of ISO-NE Administrative Costs

	Total Costs ($Millions)	Maine Share ($Millions)
2003	102.9	8.2
2004	116.2	9.3
2005	124.4	10.0
2006	114.9	9.2

Notes: Administrative Costs from ISO Annual Reports
e.g. http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2006_annual_report.pdf
Maine Share estimated at 8.0%

According to its 2007 budget, the RTO expects the growth in administrative costs to continue to increase at a rate of about 3.5% per year. Almost all of these administrative costs are recovered through RTO tariff charges which are ultimately paid by electricity consumers. For the purposes of this analysis, we will assume the ISO-NE projected annual growth rate increase of 3.5% over the five-year period from 2007-2011.[109] Recent challenges by public power entities to the level of ISO-NE administrative costs have been rejected by FERC.[110]

3. System Operating Costs

a. VAR Uplift Charges

In layman's terms, VAR uplift costs are incurred because there are some regions in New England, notably the greater Boston area, where the local transmission system is relatively weak.[111] On frequent occasions, it has not been possible to operate the system without extra voltage support from VARs. In general terms, these additional VAR costs are caused by some generating units being forced to run uneconomically to produce VARs instead of electric energy. These uneconomic costs are treated as "uplift" costs[112] and are allocated region wide. If Maine were not part of the RTO, it could avoid most, if not all, of the VAR uplift costs.

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[109] It is worth noting that ISO-NE administrative costs, on a per kWh basis, are roughly twice as great as PJM's and MISO's and slightly greater than the costs of the NYISO, CAISO and IESO. This makes ISO-NE the most expensive RTO in the country on a per kWh basis. *See*, ISO-NE 2007 Operating and Capital Budget Presentation at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/ budgfin_comm/budgfin/mtrls/2006/aug282006/2007_oper_cap_budgets_rev.pdf.

[110] See, ISO-NE *ISO New England, Inc.,* 113 FERC ¶ 61,341 (2005), *reh'g denied,* 114 FERC ¶ 61,315 (2006) (appeal in the D.C. Circuit pending).

[111] VAR uplift charges are incurred under the NEPOOL Open Access Transmission Tariff (OATT) Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service. The charges are allocated to all transmission customers based on a pro-rata share of the total monthly network load.

[112] In general, uplift costs are any costs incurred by the system where the cost recovery occurs through allocating charges to market participants, as opposed to being recovered through the price of electricity or the ancillary services. There are a number of other forms of uplift, but they are allocated to the region that causes them. As a result, Maine would not see a significant savings from avoiding these other forms of uplift.

Maine's monthly charges for VAR uplift are highly variable. In the period between January 2005 and March 2007, charges to Maine ranged from a low of $60 thousand per month to a high of $1.3 million per month. For 2005, VAR uplift charges assigned to Maine were about $6 million annually. Since 2005, VAR charges to Maine have been running at about a $2 million annual rate.

The future cost of VAR uplift is difficult to predict. On one hand, the costs are now below the 2005 level, probably because of some investments in the transmission system in greater Boston. On the other hand, the circumstances that created the voltage control problems in the Boston area may well arise again, especially in other urban areas with aging infrastructure. In fact, in recent months, VAR uplift costs relating to problems in greater Boston have been on the rise. It is also possible that the RTO and the FERC will decide to allocate other non-Maine costs to Maine in other forms of uplift. Therefore, for the purposes of our five year estimate, we will take the average annual VAR uplift charges for 2005 through March 2007 and apply it to the 2008-2017 time period.

b. Operating Reserves

For an electric system to operate reliably, the system requires operating reserves; unused capacity that can be quickly dispatched in case there is a sudden, unexpected loss of resources. Typically, the system operator will need to carry operating reserves equal to the largest single contingency (loss of supply) plus one-half of the second largest contingency. The total amount of reserves varies depending on the size of the largest two sources on-line at any given time. For example, when the DC transmission line to Hydro Quebec is fully loaded at about 1,800 MW and the Seabrook nuclear unit is operating at capacity (about 1,200 MW), the operating reserve requirement for New England is 2,400 MW. Other times, when the HQ line is not heavily loaded, the first and second contingencies may be two nuclear units and the operating reserve requirement would be about 1,800 MW. In either event, Maine is roughly 8.5% of regional monthly peak load, requiring us to carry the costs of 153 to 204 MW of operating reserves.

ISO-NE has estimated that over the past three years Maine's operating reserve costs have averaged approximately $5 million. Since operating reserves requirements would not go away under an alternative arrangement, the cost of this service would need to be incorporated into a cost/benefit analysis which compared the *status quo* to an alternative arrangement. For example, if Maine were to become a stand-alone ITC, Maine would need to carry significantly greater operating reserves. NMISA, in its comments, suggested that Maine would need to carry operating reserves of 761 MW, assuming the largest contingencies are the Calpine Westbrook plant and Maine Independent Station, which would mean that Maine would need to carry four to five times more operating reserves operating as a stand alone Transmission Organization as opposed to as part of the RTO.

c. Voltage Regulation Costs

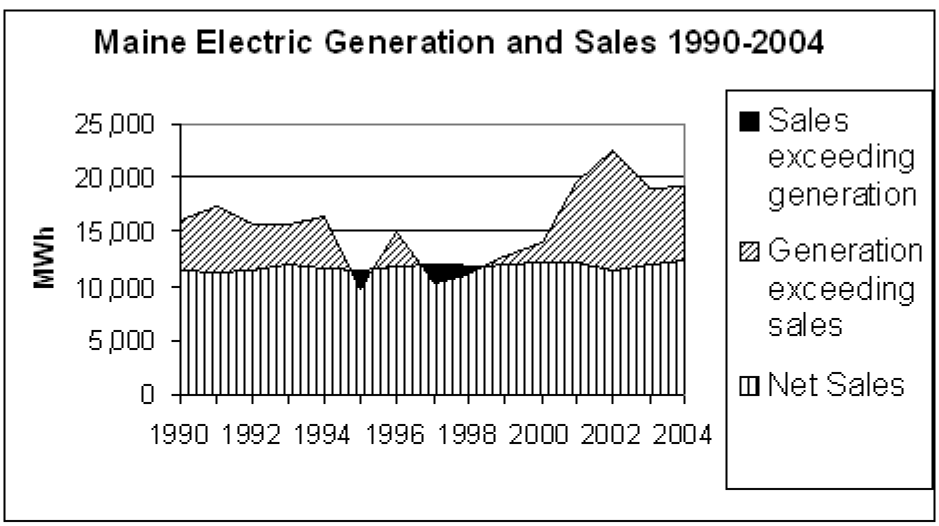
Voltage regulation is the ability of some generators to respond quickly to requests for small increases and decreases in output in order to maintain the balance between generation and usage. Requests for changes in output can occur as frequently as every four seconds. In 2006, the total RTO cost for regulation was $78.1 million,[113] of which Maine's share was in the range of $6 million. Similar to the costs of operating reserves, the costs would have to be compared to the costs for similar services in a cost-benefit analysis of an identified alternative.[114]

4. Electricity Market Costs

a. Electric Energy Costs

Maine is part of a regional electricity market, largely regulated by the RTO's administration of the energy market and related services markets. As part of the New England regional electricity markets, we are directly affected by the supply and demand for electricity in the region. In most recent years, Maine has generated significantly more electricity than it has consumed. Figure 5 shows the total generation in Maine from 1990 through 2004, as well as the total usage in the State.

Figure 5[115]



As the Figure indicates, between 1990 and 1994, in-state generation exceeded consumption by about 4,000 to 5,000 GWH per year. Stated a bit differently, generation in Maine produced about 30% to 50% more electricity than Maine customers

113 ISO-NE, 2006 Annual Report, page 80.
114 ISO-NE has asserted that a stand-alone Maine RTO might have regulation costs of three times the current cost, which suggests an increase of roughly $14 million compared to current costs. ISO-NE has not provided any basis for this assertion and we are unable to confirm it at this time.

115 The underlying data is available at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/maine html

consumed.[116] In 1995, Maine Yankee experienced major operating problems and by 1997 it was permanently inoperable. As a result, during the mid to late 1990's, Maine generation and consumption were roughly in balance. By 2000, however, large amounts of new merchant generation began coming on line and, as a result, Maine is again producing substantially more electricity than it consumes. In the years 2001 through 2004, Maine generated at least 50% more electricity than it consumed[117] with the surplus being exported outside the state.

The New England transmission system is also constrained, effectively "bottling-in" a modest amount of otherwise competitive generation in Maine during certain hours. During these constrained hours, a sub-market forms in Maine characterized by lower energy prices and increased reliability.[118]

The submarket in Maine creates an energy market that is approximately $50 million less expensive each year than the New England hub. However, the value of this differential has eroded as Maine's demand for electricity increases. In addition, there are slight increases in transfer capability between Maine and the rest of New England that will affect the differential. While we do not view this differential as a long-term "benefit" to which Maine is entitled, there are nevertheless price impacts that will be felt by Maine consumers as price separation between Maine and the rest of New England is reduced by transmission projects that increase transfer capability between Maine and the rest of New England.

b. Electricity Capacity Costs

Capacity costs are the costs associated with paying generators in New England to agree to be available during periods when the reliability of the system is threatened. Until December 2006, capacity costs have generally been a relatively small portion of the costs paid by electricity customers in Maine and New England. Recently, the FERC approved a settlement which has significantly increased the capacity costs. The settlement sets fixed capacity prices during a "transition period," from December 2006 through May 2010 at levels ranging from $3.05 to $4.10 per kilowatt-month.[119] Beginning in June 2010, capacity costs will be determined by a "Forward Capacity Market" ("FCM"), under which capacity prices will be determined through a complex auction mechanism.

Predicting Maine's capacity costs under the *status quo* is relatively easy during the transition period. On the other hand it is very difficult to predict capacity costs after the interim period either for the *status quo* or under an alternative arrangement.[120] In general, we

[116] Note that a portion of the Maine generation was lost in transmitting and distributing the generation to customers. As a result, a portion of the surplus generation was not available for sales to other regions.
[117] These figures are based on an historical data set produced by the US DOE Energy Information Administration (EIA) and data for 2005 is not yet available from the EIA. We expect the 2005 data to be generally consistent with the 2001-2004 period.
[118] The system constraint that creates the generation bottleneck also prevents Maine from sinking into temporary capacity deficiencies as often as southern New England.
[119] See March 6, 2006 Settlement Agreement in FERC Docket No. ER03-563-030, Section VIII, subsection B.
[120] There are several difficulties here. There is no experience either with the FCM market nor are there similar markets which might produce different results. It is not possible to know what bidding strategies generators will

would expect Maine capacity costs to be lower under an alternative arrangement because the alternative arrangement would be better able to differentiate between the costs of new construction in Maine, as opposed to other states in New England. If the FCM auction is not held or fails for some reason, the cost of capacity beginning in June 2010 will be $4.70, according to the settlement.[121] This would appear to be a reasonable estimate of the lowest capacity cost Maine customers would face in 2010 and 2011, and we have used it in estimating the capacity costs under the FCM market for those years.[122]

The Commission opposed the capacity settlement, specifically contesting before FERC and in court, the level of interim payments as being unreasonably high for Maine. In particular, the Commission offered evidence that the capacity costs for Maine during the interim period should be $2.00 per kw-month,[123] rather than the $3.05 to $4.10 figure preferred by the generators, ISO-NE, and those in southern New England. A $2.00 per kw-month charge would have resulted in reducing capacity payments by approximately $335 million through the end of 2011.

5. *Status Quo* Cost Summary

The Table below provides a summary of the current cost subsidies from Maine, or transfer of payments from Maine consumers to consumers of other states, under the existing ISO-NE arrangement projected over the five year period 2008-2012.

Table 2
FIVE YEAR PROJECTION FOR TRANSMISSION, VAR AND CAPACITY COSTS UNDER THE *STATUS QUO*

Cost Category	Projected Five Year Impact
Current Trans. Investment	$150,000,000
New Trans. Investment	*
VAR Type Costs	$18,000,000
Capacity Costs	$335,000,000
Total	**$503,000,000**

* The value here will depend on the amount of new transmission in Maine and elsewhere as estimated in Cases B and C previously.

employ in bidding into the FCM. And, perhaps most importantly, the results for Maine could be much higher if new transmission between Maine and southern New England is constructed.

121 See March 6, 2006 Settlement Agreement in FERC Docket No. ER03-563-030, Section VIII, subsection I.

122 By using $4.70, our capacity cost estimate is conservative. Indeed, our estimate could increase to $660 million, rather than $335 million, if the higher end of the range was used for the purposes of this study.

123 Affidavit of Thomas D. Austin, FERC Docket No. ER03-563-030, March 27, 2006.

Other costs, such as reserve, regulation and administrative costs would be incurred in any alternative arrangement.

The five year cost projection is an estimate and the actual costs may differ. For example, for the last year and a half of the five year period, we have assumed that Maine should be paying $2.00 per kw-year for capacity if we were not part of ISO-NE. If, instead, one assumed that we would be paying $4.00 during that period, then the net capacity costs cost of staying part of ISO-NE would drop by $90 million to $245 million. On the other hand, it is also possible that the transmission costs during this period could be significantly higher than our $150 million projection. On net, it appears reasonable to believe that the net costs of remaining in ISO over the five years from 2007 to 2011 will be in the range of $250 to $500 million.

In a similar analysis produced for the Interim Report, we estimated the costs for the five year period 2007 through 2011 at $616 million, somewhat higher than the figure reported here. There are several reasons for this change.

- ISO-NE noted in its comments that some new transmission projects were already reflected in rates and that our methodology effectively counted them twice. We have corrected this by excluding already completed new projects from the analysis.[124]
- The list of current projects has been updated
- We have refined the methodology used to estimate the impact of new investments on rates.
- We have excluded new transmission projects for which no cost estimate exists in the five-year outlook, but include them in the ten-year outlook.

6. <u>Ten Year Cost Projections</u>

We have also developed total cost projections based on various scenarios for how the transmission system may evolve over ten years. We considered three transmission expansion cases:

- Case A considers only the transmission projects which are relatively definite and have current cost projections,
- Case B considers all the transmission projects in the ISO's RSP07 with a range of estimated costs for those projects where no estimates exist. This case includes a direct transmission line between Northern Maine and the rest of Maine.
- Case C is identical to Case B, except that it does not include the line to Northern Maine.

Unlike the five year case, these ten year projections consider the impact of the alternative transmission projects on the market for power in Maine. In general, as the transmission ties to the rest of New England are strengthened, the price of electric energy and capacity in Maine may

[124] The five-year period used in the analysis is 2008-2012, thus any project completed prior to 2008, including the NRI, is not reflected. In its December 21, 2007 comments, BHE noted that the NRI should be included. Doing so would render Maine's transmission costs to be essentially equal regardless of which cost allocation method was used.

be increased. Table 3 shows the ten year rate impacts assuming that transmission costs are allocated by location.

Table 3
TOTAL COST OVER TEN YEAR PROJECTION UNDER THREE TRANSMISSION EXPANSION SCENARIOS TRANSMISSION COSTS ALLOCATED BY LOCATION (Millions of dollars)

Cost Categories	Case A	Case B	Case C
Transmission	200	990 – 2,400	810 – 1,930
Energy	0	0 - 500	0 - 500
Capacity	0	0 - 600	0 - 600
VAR	36	36	36
Total	236	1,026 – 3,536	846 – 3,066

Under Case A, there is no increase in the transmission and the power flows between Maine and the rest of New England. Under Cases B and C, however, there is the potential for increases in the power flows out of Maine and, therefore, the possibility that the Maine price for both electric energy and capacity will increase, although it is not clear how large such an increase will be. For the purposes of the table, we have assumed a range from no impact to an increase of $50 million per year in the energy market.[125] We have also assumed a potential annual savings of about $60 million per year in capacity costs[126]

Table 4 is similar to Table 3 except that it assumes that New England transmission costs are allocated in proportion to peak electricity usage, and Tables 5 and 6 assume transmission cost allocation methodologies that reflect an 80% location/20% peak allocation for transmission, except for NEEWS, MPRP and northern Maine projects which are directly allocated in part on a "beneficiaries pay" basis. (50% in Table 5; 75% in Table 6)

Table 4
TOTAL COSTS OVER TEN YEAR PROJECTION UNDER THREE TRANSMISSION EXPANSION SCENARIOS TRANSMISSION COSTS ALLOCATED BY PEAK USAGE - SOCIALIZED (Millions of dollars)

Cost Categories	Case A	Case B	Case C
Transmission	550	860 – 1,300	850 – 1,250
Energy	0	0 - 500	0 - 500
Capacity	0	0 - 600	0 - 600
VAR	36	36	36
Total	586	896 – 2,436	886 – 2,386

[125] In the last three years, Maine's energy costs have typically been about $50 million less than they would be if Maine paid the typical New England price as measured by the New England Hub price. This differential reflects losses and negative congestion in the Maine zone.

[126] This is based on a capacity requirement of 2,500 MW and a price differential of $2 per kw-month. The $2 figure is consistent with our approach to estimating the capacity cost impact during the first five years. It is possible hat the actually capacity cost effect could be larger or smaller than this.

Table 5
TOTAL COSTS OVER TEN YEAR PROJECTION UNDER THREE TRANSMISSION EXPANSION SCENARIOS
80 % OF TRANSMISSION COSTS ALLOCATED BY LOCATION
20% OF TRANSMISSION COSTS ALLOCATED BY PEAK USAGE
50% OF NEEWS, MPRP, & NORTHERN ME ASSUMED FOR SPECIFIC BENEFICIARIES
(Millions of dollars)

Cost Categories	Case A	Case B	Case C
Transmission	270	670 – 1,370	590 – 1,160
Energy	0	0 - 500	0 - 500
Capacity	0	0 - 600	0 - 600
VAR	36	36	36
Total	306	706 – 2,506	626 – 2,296

Table 6
TOTAL COSTS OVER TEN YEAR PROJECTION UNDER THREE TRANSMISSION EXPANSION SCENARIOS
80 % OF TRANSMISSION COSTS ALLOCATED BY LOCATION
20% OF TRANSMISSION COSTS ALLOCATED BY PEAK USAGE
75% OF NEEWS, MPRP, & NORTHERN ME ASSUMED FOR SPECIFIC BENEFICIARIES
(Millions of dollars)

Cost Categories	Case A	Case B	Case C
Transmission	270	530 – 970	490 – 870
Energy	0	0 - 500	0 - 500
Capacity	0	0 - 600	0 - 600
VAR	36	36	36
Total	306	566 – 2,106	526 – 2,006

7. Conclusion

The interactions among transmission investment, transmission cost recovery, and impacts on the electricity markets are rather complex, and defy precise quantification. The purpose of the discussion herein is to provide a range of possible results under various scenarios and cost allocations. How all of these costs get allocated over the next ten years will determine whether Maine suffers disproportionately for remaining in the ISO-NE in the long-term.

Appendix B
Related Issues for the Maine Economy

Although the focus of the Final Report is on how issues, structures and markets affect Maine and the region in terms of electricity, the future development of electric generation and transmission systems in Maine, as well as our position within regional market systems, will also affect Maine's economy in at least two distinct ways. First, changes in the generation and transmission systems may affect the cost of electricity in the State, which would, in turn, influence the overall performance of the economy. This is particularly the case for (1) businesses and industries that face national and international competition and (2) those that are electricity-intensive. Second, future development could, in and of itself, create jobs in the construction and operation of new facilities, as well as in related activities, e.g., equipment manufacturing and research and development.

In April 2007, the Brookings Institute presented the results of its study, "Charting Maine's Future" to the Governor's Council on Quality of Place. One focus of the Brookings study was on the desirability of "industry clusters", which Brookings defines as

> Groups of interrelated or similar firms in "traded" (or export) sectors such as boat-building, forest industries, information technology, biotechnology, tourism, or agriculture whose success or failure at innovation will determine the state's ability to produce greater numbers of higher-quality jobs over the long haul.[127]

With respect to electricity generation and transmission, there appear to be five likely candidates:

- Wind generation. At this time, at least, one can make a fairly strong case that wind generation in Maine and elsewhere is about to accelerate dramatically. The list of future wind projects on the table is long, driven by the interest in many New England states in using portfolio requirements to encourage new development, concerns over greenhouse gas emissions, and the fairly rapid commercialization of the technology. It is somewhat more difficult to map out what the economic impacts on Maine will be. Clearly, there would be a significant number of construction jobs to construct the generation facilities and, depending on where they were sited, to construct additional transmission generation. Once constructed, the economic impact is probably also positive, although more difficult to estimate. There would be a certain number of jobs operating and maintaining the wind facilities. There could be benefits if the make annual payments to landowners, as they might if the facilities were located on agricultural land.[128] Finally, it is conceivable that large scale wind development could encourage Maine firms become involved in either producing equipment needed for wind power production and/or expertise in the operation and maintenance of wind facilities located outside the state.

[127] Brookings Institute, "Charting Maine's Future", page 7.
[128] On the other hand, there could be some negative impacts if the generators were sited in places which made vacationing and recreation less attractive in the eyes of the customers in that industry.

- Biomass Generation. A significant expansion of biomass generation would likely lead to additional economic activity in developing and harvesting biomass fuel, in addition to the construction and operations jobs associated with most forms of electricity generation.

- Other forms of renewable power. While wind and biomass are the forms of renewable generation which have reached commercial scale development at this time, there are other possible new renewable technologies suited to be sited in Maine. For example, the Gulf of Maine appears to have a strong potential for tidal power development and, in the long run, could become a cluster where few other areas of the US could effectively compete.

- Additional Natural Gas and Liquefied Natural Gas Electricity production. Over the past decade, Maine has seen a substantial increase in the amount of gas fired generation located in the state; this has resulted in both construction and operation jobs. On the other hand, once constructed, gas fired plants do not require large amounts of labor for their operations. In fact, by far the major operating cost of gas plants is purchasing gas fuel which does not create a significant number of jobs for the Maine economy.

- Expanding the Electric Transmission System. Although expanding the electric transmission system would produce relatively few jobs once construction has been competed, it is possible that Maine firms could find a niche in the design, licensing, and construction of new transmission lines in areas outside Maine as well.

In conclusion, there appear to be areas where the potential exists for Maine to develop economic clusters around electricity generation or transmission. If this path is to be fully explored, however, a broad range of participants and policy-makers must be involved.