STATE OF MAINE
PUBLIC UTILITIES COMMISSION
242 STATE STREET
18 STATE HOUSE STATION
AUGUSTA, MAINE
04333-0018

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COMMISSIONERS

April 15, 2008

Honorable Philip Bartlett, Senate Chair
Honorable Lawrence Bliss, House Chair
Joint Standing Committee on Utilities and Energy
115 State House Station
Augusta, Maine 04333

Re: Electric Resource Adequacy Report and Plan

Dear Senator Bartlett and Representative Bliss:

During its 2006 session, the Legislature enacted an Act to Enhance Maine's Energy Independence and Security (Act). P.L. 2005, ch. 677. Part C of the Act (codified at 35-A M.R.S.A. §§3210-C, 3210-D) directed the Commission to establish an electric resource adequacy plan and authorized the Commission to direct transmission and distribution utilities to enter into long-term contracts for capacity resources and associated energy.

The Commission engaged London Economics International (LEI) to prepare the resource adequacy report and plan. As required by the Commission's implementing rules (Chapter 316), a draft report was released for public comment. The final report has been revised to address the comments submitted to the Commission.

In light of some of the comments, we note that the purpose and scope of the report was to consolidate and synthesize publicly available material, rather than to perform any independent modeling analysis. In addition, the report was intended to outline objectives and strategies for future long-term contracting efforts. At this juncture, there is insufficient information to be able to perform any extensive quantitative analysis of possible contracts. However, given the current landscape and a review of existing ISO-NE market rules, the report does outline a conceptual strategic framework for minimizing exposure or hedging wholesale market costs of electricity, with specific emphasis, where appropriate, on potential use of contracts. For instance, the report recognizes inherent value in increasing demand-side resources and wind generation in Maine.

However, whether a particular approach, or type of contract, is in fact going to produce benefits that outweigh its costs is an empirical question. As such, it cannot be analyzed conceptually, but must be measured against concrete contract offerings and other developments in the market. Furthermore, the report notes, "without more certainty on the transmission investments, it is difficult to craft an optimal strategy for securing the least cost and most reliable electric supply." The Commission recognizes that the timing and character of transmission investment will influence the type of generation investment that is viable and economic, and also directly impact both the energy and capacity markets.

As part of the long term contracting requirement of the Act, the Commission with the assistance of LEI will develop an RFP in a public process and expects to solicit proposals within the next several months. Within the scope of the competitive solicitation, the Commission will develop a methodology for assessing the cost-benefit tradeoff of possible long term contract(s) and underlying investment(s). The solicitation and contracts will be carefully designed to work alongside current market arrangements and pursue long run efficiencies, as well as hedge exposure to infrastructure and wholesale market costs for ratepayers.

The final electric resource adequacy report and plan is attached. If you have any questions or comments regarding the attached document, please contact us.

Sincerely,

Kurt Adams, Chairman
Maine Public Utilities Commission

On behalf of

Sharon M. Reishus
Vendean V. Vafiades

Commissioners
Maine Public Utilities Commission

Attachment

cc: Utilities and Energy Committee Members
Lucia Nixon, Legislative Analyst

A Resource Adequacy Plan for Maine: Consideration of Electricity Sector Investment Strategies

Prepared for Maine Public Utilities Commission by London Economics International LLC

April 15, 2008

LONDON ECONOMICS

Executive Summary

London Economics International LLC ("LEI") has been engaged by the State of Maine's Public Utilities Commission ("MPUC") to assist with the procurement of long-term contracts for capacity and energy resources per the requirements of the Act to Enhance Maine's Energy Independence and Security ("Act"). The Act authorized the MPUC to direct Maine's investor-owned utilities ("IOU") to enter into long-term agreements for capacity resources. In particular, the Act contained detailed standards, policies and procedures governing the Commission's contracting authority. The Act also directed the MPUC to develop an electric resource adequacy plan to aid in the development of a strategy for the pursuit of these long-term contracts. The resource adequacy plan was specifically intended to ensure grid reliability and the availability of electricity to consumers at lowest reasonable cost.

This paper lays out LEI's recommendations for a resource adequacy plan for Maine pursuant to the Act. Given the depth of technical analysis already completed on infrastructure needs, the MPUC was primarily interested in a resource adequacy plan that distilled the information and recommendations found in existing regional and utility assessments into a cohesive strategy for minimizing future costs of electricity to ratepayers in the state. Therefore, this report builds up a set of recommendations for a long term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the newly-created Forward Capacity Market ("FCM"), examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO New England ("ISO-NE"), as well as relevant sub-regional planning studies.[1]

Adequate supply and transmission congestion have benefited ratepayers to date with respect to energy market costs

Maine has much more generation capacity than necessary to meet its internal electrical load currently and for the foreseeable future. Moreover, Maine's energy costs have been lower than those of other states in New England, mainly because of its resource mix and demand profile. The status quo in Maine is characterized by transmission congestion, which isolates Maine from higher price situations in the rest of New England. Transmission congestion costs in Locational Marginal Prices ("LMPs") reduce overall prices paid for electricity by consumers. Technically, congestion has effectively limited Maine's exposure to higher energy costs by

[1] This report documents and relies on information prepared by the electric utilities as well as ISO New England, including utility plans and proposals for transmission expansion. LEI has not independently analyzed their assumptions or conclusions. Notably, none of the proposed transmission projects discussed in this report have yet been reviewed or approved by the MPUC. Therefore, neither the need for nor the purported benefits of these transmission projects have been reviewed or determined.

isolating Maine from the rest of New England during many on-peak hours. Continued availability of existing resources and the addition of low variable cost resources – supply and demand-side – would give Maine the opportunity to maintain its cost advantage as compared to the rest of New England.

Capacity market costs also depend on supply-demand balance and transmission congestion

In isolation of system-wide dynamics, Maine has adequate generation. However, in the rest of the New England system, the current balanced supply-demand situation is likely to approach deficit capacity conditions in the short to medium term. As a member of the integrated New England power system, Maine is required by Market Rules to pay a portion of the costs of the FCM for procurement of installed capacity to secure the reliability of the system as a whole. The FCM will create costs for Maine ratepayers that have not previously existed, although it is possible for policymakers in Maine to take steps to minimize those costs. The abundance of local generation coupled with transmission interconnection limits can result in potentially lower costs in the capacity market in the near term. In its latest filing to FERC, ISO-NE stated that Maine would be an export-constrained zone for the first Forward Capacity Auction ("FCA") for the 2010 capability period. The Market Rules provide that export-constrained zones can have a lower capacity clearing price than the rest of the system, if the zone's auction "closes" after the auction for the Rest of Pool. In other words, if Maine generators are willing to offer to sell capacity below the price earned by resources in the Rest of Pool, Maine's overall costs should be lower than what they would otherwise be.

A number of resource strategy recommendations emerge from these considerations. First, if Maine can continue to maintain its designation as an export-constrained Load Zone in future FCAs, and Maine's generators are encouraged to price below the auction price for the Rest of Pool, then Maine can secure a lower capacity price and therefore minimize its costs of capacity. Given the Market Rules, incentive mechanisms that lower the legitimate costs of new generation in Maine would also increase the likelihood of a lower clearing price in the Maine auction.

Potential development of new transmission, generation and demand-side resources should all be considered as part of a long term strategy

ISO-NE documents and utility planning studies reviewed by LEI stated their concerns on transmission reliability in and around the Maine system, and emphasized the need for transmission investments and upgrades to address these reliability issues. Although it is not yet certain whether all the proposed transmission investments will come to be approved, it is likely that some transmission projects will be realized. There are a number of strategic implications of potential transmission investments. First, transmission investments that expand the transmission capability between Maine and the Rest of Pool would reduce the chances of an Export-constrained Zone designation, holding all else equal. Maine's capacity price would therefore be based on the New England-wide auction results, and Maine would no longer be able to secure a lower price than rest of New England. Second, the addition of Maine's resources to the overall FCA may result in a lower system-wide clearing price of capacity, which would benefit consumers in all of New England. Contracts and other incentive mechanisms that encourage the maximum availability of resources would help achieve this goal. Finally, demand-side resources that reduce Maine's share of system peak load would also reduce Maine ratepayers' share of regional costs.

On the energy market side, transmission investment would reduce the congestion cost component in Maine's LMPs, which could raise overall energy costs to ratepayers, unless offset by other market effects or contractual vehicles. For example, access to Maine's low cost generation can reduce the energy cost component of LMPs on a system-wide basis, and lead to lower LMPs. Without detailed modeling analysis and understanding of transmission investment decisions and generation investment response, it is difficult to determine a priori whether new transmission would increase or decrease energy market costs for Maine ratepayers.

Finally, generation and transmission investments are in many cases complements (e.g., new generation in Maine will require some new transmission investments), but can also be substitutes (transmission investments can replace the need for local generation development and vice versa). The quantity, type, and timing of new generation resources necessary to minimize the costs of energy and capacity to Maine consumers will depend on the specific characteristics of transmission investment undertaken. We would therefore recommend that the strategic plan for Maine's resource adequacy include consideration of the potential range of future transmission investments.

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1 Introduction

The Act to Enhance Maine's Energy Independence and Security (the "Act") authorized the Maine Public Utility Commission ("MPUC") to direct the State's investor-owned utilities ("IOUs") to enter into long-term agreements for capacity resources.[2] The Act also directed the MPUC to develop a long-term plan for electric resource adequacy for the State to ensure grid reliability and the provision or availability of electricity to consumers at the lowest cost.[3] Given the depth of technical analysis already completed on infrastructure needs, the MPUC was primarily interested in a resource adequacy plan that distilled the information and recommendations found in those regional and utility assessment. We therefore reviewed the reports produced by ISO-New England ("ISO-NE"), the Northern Maine Independent System Administrator ("NMISA"), as well as the compliance filings and demand forecasts by the utilities. In addition, we reviewed the current supply-demand situation vis-à-vis the market rules for energy and the newly-created Forward Capacity Market ("FCM"). The combined understanding from these various sources led to the development of conclusions in this report. In effect, this report is a Resource Adequacy Plan, based on already publicly available information about the electricity needs of the state, both in the short and long-term.

1.1 Background on the Act

During its 2006 session, the Maine Legislature enacted an Act to Enhance Maine's Energy Independence and Security (the "Act"). P.L. 2005, ch. 677. Part C of the Act (codified at 35-A M.R.S.A. §§ 3210-C, 3210-D) addressed capacity resource adequacy by authorizing the Commission to direct large investor-owned transmission and distribution utilities[4] (T&D Utilities) to enter into long-term contracts for capacity resources and by directing the Commission to establish an electric resource adequacy plan. In particular, the Act contained detailed standards, policies and procedures governing the Commission's contracting authority and required the adoption of a resource adequacy plan for the purpose of ensuring grid reliability and the availability of electricity to consumers at the lowest cost. The Act required the Commission to implement the long-term contracting section and establish the resource adequacy plan through the adoption of rules. On June 21, 2007, the Commission adopted the implementing rules (Chapter 316).

1.2 Structure of this Report

Prior to delving into the detailed technical planning analysis, it is important to understand the current supply and demand situation in the state. Section 2 of the report provides this important foundational element by describing the existing resource base in Maine, vis-à-vis that

[2] See Part C of the Act, 35-A M.R.S.A. §§ 3210-C.

[3] See Part C of the Act, 35-A M.R.S.A. §§ 3210-D.

[4] Central Maine Power Company and Bangor Hydro-Electric Company are the two utilities that meet the statutory definition of large investor-owned transmission and distribution utility (utilities serving more than 50,000 customers). 35-A M.R.S.A. § 3201(12).

of neighboring states in New England. We also review electricity load conditions and prospects for growth in demand. When it comes to power system analysis, the State of Maine is particularly complex due to the fact that its grid is divided into two sub-regions controlled by different bodies: ISO-NE controls the majority of Maine (approximately 95% of the State's installed capacity), while NMISA controls a small part of Northern Maine. This section of the report combines the information we have from each operator so that we have a snapshot of the current situation on a state level.

In Section 3 of this paper, we summarize the analysis and conclusions of relevant studies that have recently been performed by ISO-NE, NMISA, along with the IOUs' reliability reports submitted to the Maine Public Utilities Commission, with particular focus on proposals for new transmission. Because transmission development in Maine has several implications, including on reliability, new resource development, and consumer costs, it should be considered as part of Maine's resource adequacy plan and any long-term supply procurement strategy.

The New England wholesale electric market is a multi-settlement energy market containing a Day-Ahead and a Real-Time market, as well as a newly-created FCM. New England is separated into eight load zones for purposes of energy market settlement (Maine is one of them). In the FCM, and specifically for the first Forward Capacity Auction ("FCA") in February 2008, Maine has been designated an export-constrained zone, which means that it may have prices that are lower than those in rest of New England. Sections 4 and 5, respectively, discuss the implications of the existing supply-demand situation on capacity and energy market prices, in the context of (current and evolving) ISO-NE Market Rules.

1.3 Summary of Key Insights

The key statistics for electricity supply and demand are telling. With over 1,250 MW of surplus capacity (above peak demand) currently, and demand growth of only 370 MW on a cumulative basis, projected for the next ten years statewide, Maine is very well positioned in terms of electricity generation, especially if we take into account that its strengthening Demand Response ("DR") program is on track to become one of the largest in the United States,[5] further reducing its peak load growth. [6] Section 2 provides detailed analysis of these figures and other descriptive statistics, including the age of the resource base, the fuel mix (vis-à-vis the state's Renewable Portfolio Standard program), and reserve margin projections. In summary, Maine has much more generation capacity than necessary to meet its internal load, as opposed to the rest of the New England system where the situation is more balanced in the short-term and could approach deficit conditions in the medium-term, without additional resource development.

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[5] Synapse, Increasing Demand Response in Maine, Draft Report, November 2007, page 1.

[6] When we discuss demand-side resources and Demand Response program, consistent with ISO-NE program terminology and accepted industry definitions, we are referring to all demand-side resources, including energy efficiency, conservation, peak demand response, and distributed generation.

Historical trends in locational marginal prices ("LMPs") highlight the persistence of congestion over the recent few years between Maine and rest of New England.[7] In addition, congestion within Maine is also on the rise. Indeed, generators have argued for years for the need for transmission reinforcement, so that they can run their power plants more frequently and sell more electricity. Congestion costs, however, have produced a lower energy cost for Maine ratepayers, especially for on-peak periods, as compared to consumers in other parts if New England. Market changes causing an increase in congestion, such as additional lower cost generation, could be beneficial to ratepayers, as this further (more frequently) isolates Maine from the rest of New England. On the other hand, such changes may not be sustainable on a cost-effective basis in the longer term. In fact, market changes that reduce the negative congestion component may occur; for example, new transmission investment. Such changes may raise LMPs and therefore energy costs to ratepayers. Evaluation of the overall economic costs and benefits associated with congestion, including the tradeoff between lower LMPs from maintaining congestion and the increased reliability and security of supply from relieving congestion, will be informative to future decisions and strategies.

Based on the review of the current supply-demand situation, and the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies, Maine currently has more than sufficient capacity to reliably meet the state's electrical demand. Moreover, all the studies are optimistic that Maine will be able to meet its electricity demand in the medium-term and even further out in the future. These studies also discussed the state of Maine's transmission system. All the studies reviewed discussed transmission congestion and some studies discussed the need for transmission upgrades or expansions in the context of system reliability.

As will be discussed later in Section 3, studies reviewed by LEI indicate that thermal overloads, voltage violations, and capacity bottlenecks exist in critical areas of the Maine network. Such conditions can lead to local and sub-regional supply interruptions. All the studies therefore emphasized the need for transmission investments and upgrades to address such reliability issues.[8] Some of these transmission projects include the Maine Power Connection, Rumford-Woodstock-Kimball Road Corridor Transmission Project, Maguire Road Switching Station 115 kV Project, and transmission upgrades in Southern Maine.

The development of the FCM will create costs for Maine ratepayers that have not previously been felt. It is anticipated that ratepayers in Maine will be responsible for approximately 7.5% of the total capacity costs from the FCM, based on the current peak load share. ISO-NE puts the system-wide costs of capacity at over $1.9 billion in 2010 and $2.5 billion in 2016 (for New England as a whole) in the latest Regional System Plan ("RSP"); these are not insignificant market costs for Maine ratepayers ($142.5 million in 2010 rising to $187.5 million by 2016, if Maine's share of peak load stays at 7.5%). In its latest filing to the Federal Energy Regulatory Commission ("FERC"), ISO-NE stated that Maine would be an export-constrained zone for the

[7] For purposes of this study, and data that was available at the time the study was initiated, LEI reviewed the historical price trends for the period of January 2005 and September 2007.

[8] Some of these issues may also be addressed by generation and demand-side investments.

first FCA in February 2008. If the state can continue to maintain the following two conditions: 1) Maine needs to be designated as an export-constrained Load Zone, and 2) Maine's auction needs to close after the auction for the Rest of Pool, then Maine can secure a lower capacity price.

1.4 Road map for developing a strategy for resource adequacy

Historically, congestion has helped limit Maine's exposure to rising energy costs. Congestion – in capacity terms – will also help Maine in the first FCA by allowing it to hold a separate auction for capacity and providing an opportunity for lower capacity clearing prices in the export designated Maine zone as compared to the rest of New England. Strategies that ensure the continued availability of existing and the development of new low cost supply resources in Maine will preserve the state's position in this respect, assuming all else equal.

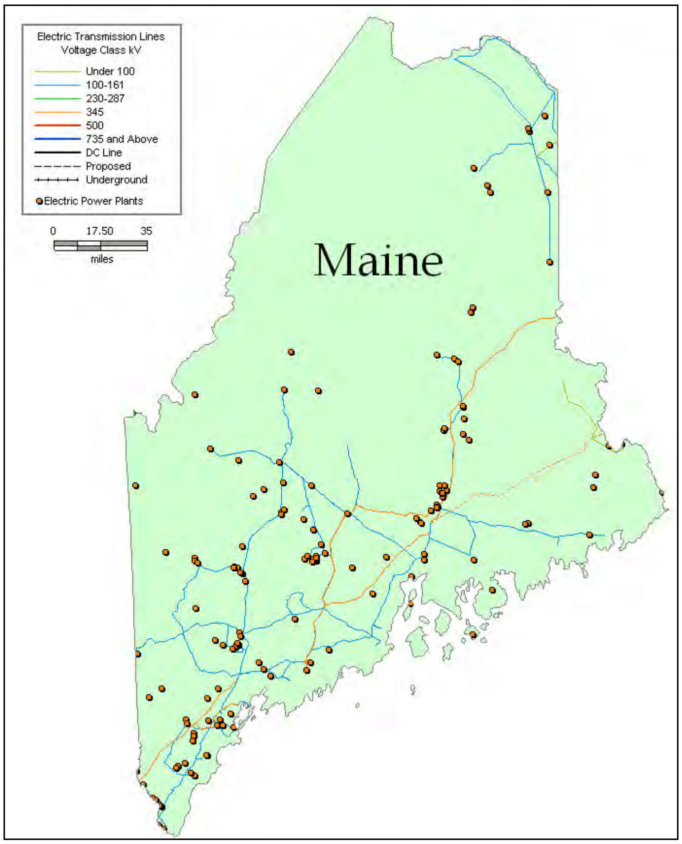
In the longer term, the analysis should consider the potential that some form of transmission investment could reduce the frequency and magnitude of congestion within Maine and between Maine and rest of New England. Assuming Maine is no longer able to isolate itself from price trends in rest of New England, strategic focus will need to shift to evolving resources that reduce overall market costs through supply shifts and other direct market impacts. Because the energy and capacity markets employ a uniform market clearing price, it is possible to reduce market-wide costs if sufficient quantities of new low-cost supply and/or demand resources are added to displace the price-setting unit. Maine may be particularly well-suited for such new resource development given potentially lower new build costs associated with cheaper land, lower labor costs, etc. Demand resources provide additional benefits by reducing Maine's allocated share of market costs in the long run (after demand reconstitution takes place).

Thus, in either case, Maine will want to motivate generation investment that results in the lowest possible capacity clearing prices in the FCAs and in the hourly energy markets. Contracts for existing and new generation can be created to encourage and motivate generation resources to participate in ISO-NE markets to the fullest extent possible. And in particular, if sufficient volumes of low cost renewable resources are developed, they can reduce LMPs by impacting the energy cost component of system-wide LMPs.

2 Maine's electricity supply and demand

In 2006, Maine's total energy consumption reached 12,554 GWh, with an annual peak of 2,207 MW.[9] Its installed summer capacity is approximately 3,450 MW, with natural gas and oil being the dominant fuels in capacity terms, with almost no 'traditional' baseload capacity (like coal or nuclear).[10] The state is experiencing a modest load growth (less than 2% p.a.), while more than 500 MW of new supply-side capacity is proposed to come online by 2009.[11]

Figure 1. Map of existing transmission lines and generation plants in Maine



Source: Energy Velocity, 2006 Data

Figure 1 above illustrates the key components of the Maine generation system, mostly concentrated in the South-Western part of the state, and transmission network, with approximately 1,500 miles of 345 kV and 115 kV transmission lines within its borders (see

9 ISO-NE, RSP 2007 data. The value for Maine total annual peak (2,207 MW) is the sum of winter peak for Northern Maine and summer peak for rest of Maine, representing non-coincidental peak demand.

10 ISO-NE, RSP 2007 and NMISA, Seven-Year Outlook.

11 ISO-NE, Interconnection Request Queue, January 2008.

section 3 for more details). Note that the Northern part of Maine constitutes a network separate from the main system. Indeed, the State of Maine is particularly complex due to its grid being divided into two sub-regions: the majority of Maine (approximately 95% in terms of installed generating capacity) is under the control of ISO-NE, while a small part of Northern Maine is under the control of NMISA. The following supply and demand analysis takes into account this distinction and tries, whenever the data is available, to present the information on a combined basis for the state as a whole.

2.1 Demand analysis

Maine has one of the lowest energy and peak loads among New England states (third lowest only to Vermont and Rhode Island). While Northern Maine continues to be a winter peaking system, the rest of Maine (i.e., ISO-controlled area of Maine) was a winter peaking system until 2001. In contrast, ISO-New England has been a summer peaking system since at least 1991. Both Maine and New England's peak electricity consumption have been growing faster than their consumption, resulting in a declining load factor.[12]

2.1.1 Current demand situation

In 2006, Maine's total energy consumption reached 12,554 GWh while the rest of the New England system consumed 120,352 GWh.[13] Figure 2 shows the breakdown between Northern Maine (NMISA), the rest of Maine (i.e., ISO-controlled area of Maine) and the rest of the New England system. The annual load of the ISO-controlled area of Maine decreased by almost 4% between 2005 and 2006, while the rest of the system's load decreased by about 3%. This reduction in electricity consumption in the region is due in large part to milder than normal weather patterns, compounded by an increase in retail prices, wholesale demand-response programs, and consumer outreach programs.

Figure 2. Energy data comparison between Northern Maine, rest of Maine and the rest of the New England system, 2006

	2006	Net Energy (GWh)	Annual Growth	Annual Peak (MW)	Annual Growth	Load Factor
MAINE	Northern Maine	823	-	139	< 2%	66.80%
	Rest of Maine	11,731	-3.92%	2,068	1.52%	64.80%
	Maine Total	12,554	-	2,207	-	-
REST OF SYSTEM		120,352	-3.13%	26,062	4.63%	53.60%

Source: ISO-NE 2007, NMSIA Data.

Note: The value for Maine total Annual Peak (2,207 MW) is the sum of winter peak for Northern Maine and summer peak for rest of Maine, representing non-coincidental peak demand.

12 In 2006, Maine had a load factor of approximately 65% compared to the rest of the New England system's 54%.

13 ISO-NE, RSP 2007 data.

While total energy consumption declined, peak demand increased. The 2006 peak demand for Maine was 2,207 MW with a load growth of less than 2% and 1.5% for Northern Maine and rest of Maine, respectively. In comparison, the rest of the system's summer peak was 26,062 MW, growing 4.6% between 2005 and 2006. The table above (see Figure 2) shows that peak electricity consumption in New England and in Maine has been growing faster than average consumption, resulting in a declining electricity consumption load factor. ISO-NE attributes this trend to an increase in air-conditioning penetration, especially in southern New England, as the use of air-conditioning usually occurs during peak hours.[14] This has led to an increase in summer peak use relative to total annual consumption or average use. Long-term implications of this trend will be discussed in more detail in Section 5 of this report.

2.1.2 Historical demand analysis

Over the past five years (2001-06), Northern Maine's electrical load has grown at a compound annual growth rate ("CAGR") of 0.8% p.a., while the rest of Maine's net energy load decreased by 0.5% p.a. on average. The decrease in net energy growth is largely attributable to the significant decline in total consumption in 2006 (see section 2.1.1). If the year-on-year trend for 2006 is ignored, the CAGR for energy requirements for the rest of Maine would have *increased* by 0.4% p.a.

Over the same period, the State of Maine's summer peak grew at a CAGR of 1.2% p.a., while the rest of the system grew at 2.4% p.a. The rest of the New England system's electrical load growth was around 1.0% p.a. on average (see Figure 3).

Figure 3. Energy growth comparison between Northern Maine, rest of Maine and the rest of the system, 2001-2006

	2001-2006	5-Year Energy Consumption Growth	5-Year Annual Peak Growth
MAINE	Northern Maine	0.8%	0.3%*
	ISO-Controlled Maine	-0.5%	1.2%
REST OF SYSTEM		1.0%	2.4%

Notes:
** Data covers the 2002 through the 2006 period. Note that Northern Maine's peak growth results from the combination of a 2.2% annual peak growth from 2002 to 2004 and a subsequent rapid decrease in peak growth.*
** Maine's negative rate of change in consumption has been influenced by changes in how industrial load is represented on the system. With the opening of wholesale markets and the rolling expiration of qualified facility contracts from the PURPA era, there has been a propensity for industrial customers to transform their facilities and/or build "inside-the fence" generation so that they can self-provide electricity. This has then reduced the metered consumption on the Maine system. This phenomenon is discussed in greater detail in Section 2.1.4 below.*

Source: ISO-NE 2007, MPS Load Data 2006

[14] ISO-NE, RSP 2007, page 4.

A variety of demographic and macro-economic factors underlie the differences in growth rates between Maine and New England as a whole. Figure 4 below identifies some of the differences in the macro-economic environment between the two regions. While population has increased by 0.47% p.a. and 0.51% p.a. in Maine and New England respectively, real gross state product (in 1996 real US dollar terms) has increased 1.84% p.a. and 2.97% p.a. respectively, resulting in a higher growth rate for real gross state product per capita for New England as a whole.

Figure 4. Macro-economic data comparison between Maine and New England, 1991-2006

Indicator	CAGR (%)	
	Maine	NE
Actual Net Energy for Load (GWh)	1.102	1.309
Nominal Price of Electricity (cents/kwh)	2.323	2.920
New England Composite CPI (Base=1996)	2.708	2.708
Real Price of Electricity (cents/kwh)	-0.370	0.211
Population: Total, (Ths., #)	0.472	0.506
Households, (Ths., #)	0.909	0.715
Employment: Total Nonagricultural, (Ths.)	1.191	0.934
Real Income: Total Personal, (Mil., 96$)	1.918	2.248
Real Income: Total Disposable, (Mil., 96$)	1.995	2.144
Real Gross State Product, (Mil. 96$)	1.841	2.965
Nominal Income: Total Personal, (Mil., $)	4.674	5.012
Nominal Income: Total Disposable, (Mil., $)	4.753	4.906
Actual Cooling Degree Days (base 65F)	1.147	1.223
Actual Heating Degree Days (base 65F)	-1.391	-0.247

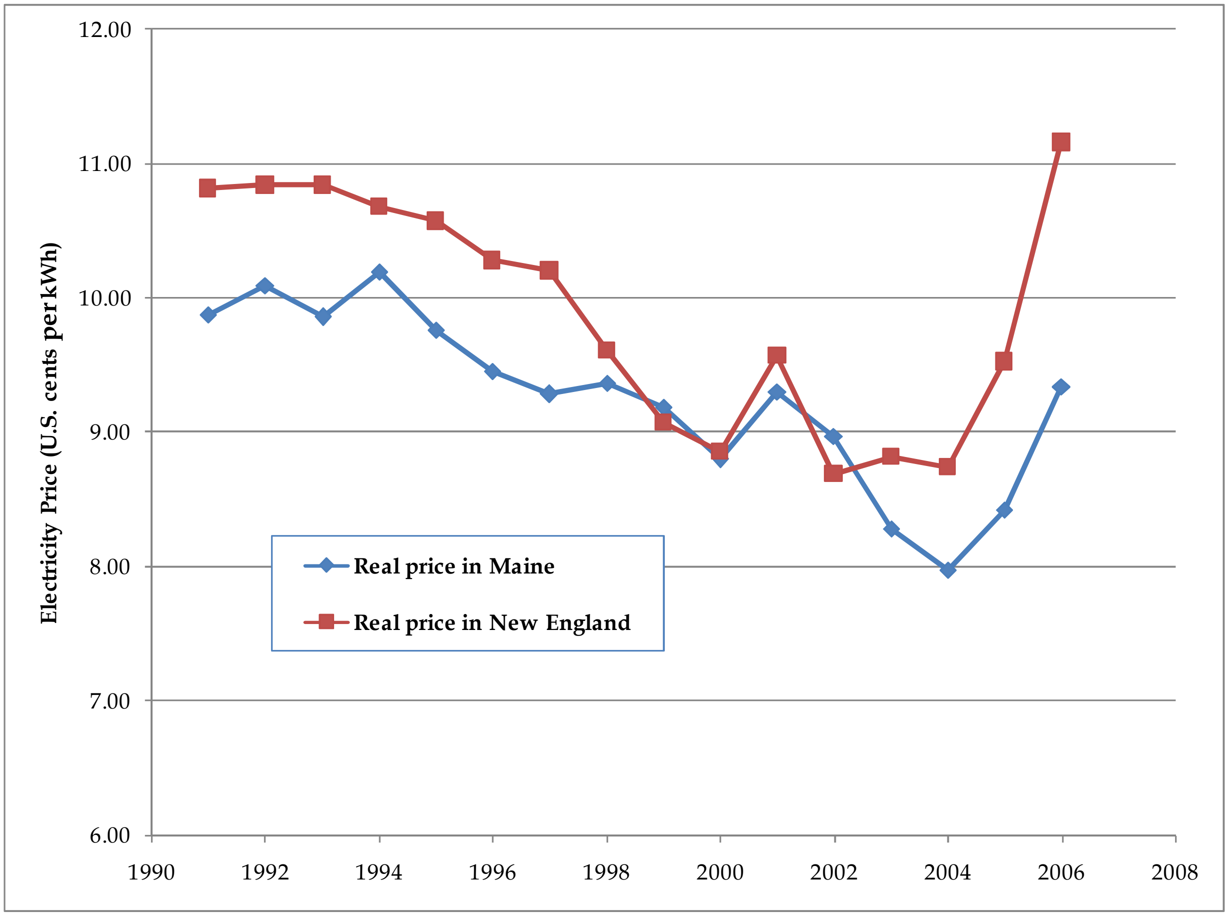
Source: ISO-NE 2007 Forecast Data

On an average basis from 1991 through 2006, Maine has been experiencing an overall decline in real electric energy prices, while New England's real prices have been slowly growing at an average rate of 0.2% p.a. over the same period. However, the year-on-year trends include both price increases and declines, as seen in Figure 5. Both Maine and New England have experienced a real price increase since 2004. In nominal terms, prices in Maine have been increasing at 2.3% p.a. since 1991, resulting in a growth of more than 40% over the 1991-2006 period, while New England nominal prices have been increasing at 2.9% p.a., resulting in a total increase of 54%.[15,16]

[15] ISO-NE 2007 Forecast Data File, from the Forecast Report of Capacity, Energy, Loads and Transmission (CELT) 2007 - 2016.

[16] According to the MPUC, electricity costs in Maine and New England have increased by 55% since 1990. *Source: MPUC, Draft Final Report, Pursuant to "A Resolve to Direct the Public Utilities Commission to Examine Continued*

Figure 5. Real electricity prices in Maine and New England, 1991-2006



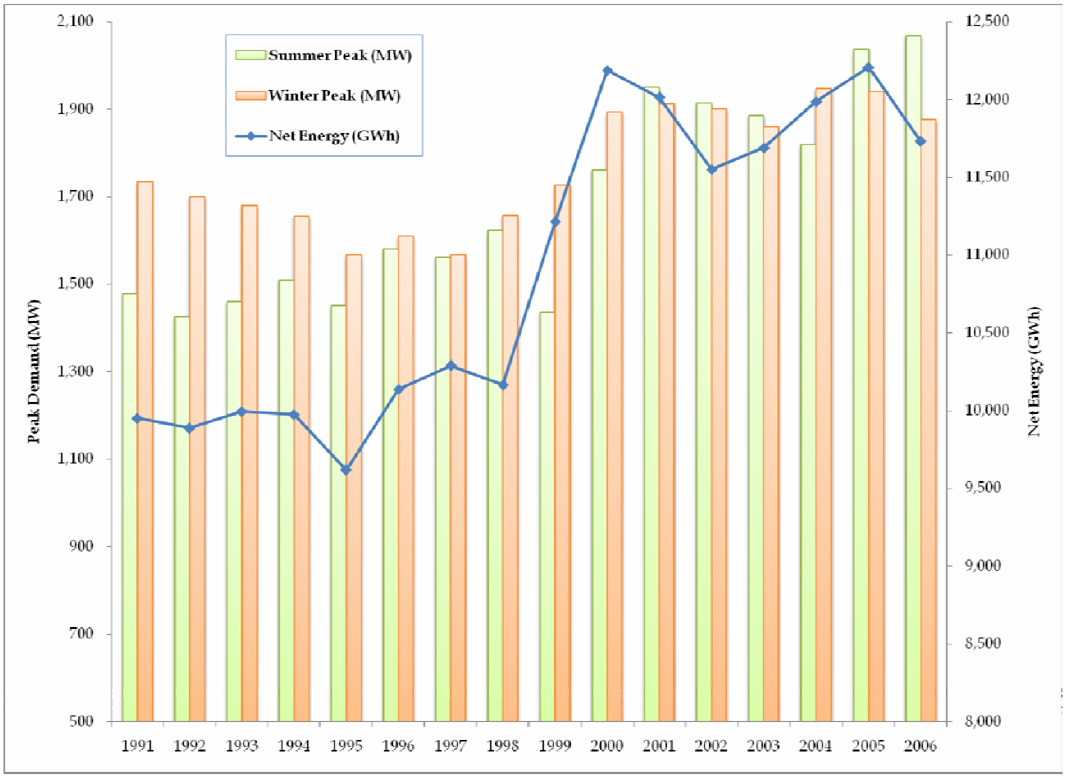
Source: *2007 CELT Data*

ISO-controlled Maine was a winter peaking system until 2001, after which time the unadjusted peak occurred in the summer season, with the exception of the year 2004.[17] In New England, summer has been the peaking season since at least 1991, with the sole exception being 1992. Northern Maine continues to be a winter peaking system. Figure 6 below represents a graph of Maine's historical peak demand contrasting winter and summer peaks, and consumption growth trends for the past fifteen years. These statistics are based on unadjusted data and therefore are not weather-normalized.

Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization", December 4, 2007.

[17] In January 2004, New England experienced extremely low temperatures resulting in a record winter-peak electrical demand.

Figure 6. Historical analysis of ISO-controlled Maine's peak demand and consumption growth, 1991-2006



Note: *This diagram does not include historical data from Northern Maine.*

Source: ISO-NE 2007 Forecast Data

2.1.3 Comparison of load forecast – RSP 2006 vs. RSP 2007

ISO-NE has modified its long-term load forecast in the past year from last year's integrated RSP. Figure 7 below shows that ISO-NE reduced its projections for peak-load and energy-load growth in both New England and Maine from 2006 to 2007. The reduction in the projected growth rates from the 2006 Regional System Plan ("2006 RSP") is due in part to the increased electricity capacity and electric energy prices in Maine – reflecting the rate of inflation and cost of fuels – and in part to the region's increased penetration of air-conditioning load.[18]

The ISO-NE latest ten-year (2007-2016) demand forecast study expects the State of Maine's peak-load compounded annual growth rate to be around 1.8% per year (compared to 1.7% for New England), and the energy-load growth rate to be around 1.4% per year, (compared to 1.2% for New England).[19]

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[18] ISO-NE, RSP 2007, page 4.

[19] ISO-NE, RSP 2007, page 23.

Figure 7. Comparison of ISO-NE annual load forecasts, 2006 and 2007

	Net Energy Load		Peak Demand	
	2006 Forecast	2007 Forecast	2006 Forecast	2007 Forecast
New England	1.3%	1.2%	1.9%	1.7%
Maine	1.7%	1.4%	2.1%	1.8%

Source: ISO-NE RSP 2006, 2007

2.1.4 Projected load growth prospects: models and results

To be able to rationalize economic strategy and infrastructure investment needs, several anticipated load growth forecasts in Maine were reviewed in order to understand how electricity consumption trends will evolve. Here we have reviewed ISO-NE's load forecast[20] and the load forecast performed by three investor-owned utilities: Bangor Hydro Electric ("BHE"), Maine Public Service ("MPS") and Central Maine Power ("CMP").

Comparative Overview

A comparison of the forecasts (see Figure 9 and discussion below) highlights large discrepancies between the ISO and the IOUs' projections. As we discuss below, forecasting methodologies, models, assumptions, and inputs differ greatly from one entity to another, leading to differing results in the future, especially when the outputs of different methods and input assumptions are compounded over several years.

It is important to note that ISO-NE and the IOUs define service areas differently. While there is some geographical overlap between the Maine ISO-NE RSP subareas[21] and the IOUs' service territories, two distinctions should be considered: 1) MPS is not an operating company within the ISO-NE control area; and 2) the RSP subareas and the IOUs' service territories cross state boundaries (i.e., CMP has some load in New Hampshire and a small portion of New Hampshire's load is considered to be within the ME RSP sub-area).[22] Although this will result in a bias when it comes to load forecasting, we expect such a bias to be minimal in the long-term and to have negligible impact on the conclusions of this report. Figure 8 illustrates the operating companies' shares in terms of ISO-NE's RSP subareas.

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[20] We have focused on ISO-NE's 50/50 weather normalized baseline. The 50/50 peak load forecast is a forecast of peak load that has a 50% chance of being exceeded. ISO-NE also has different probability cases (representing different weather conditions), and high and low economic growth sensitivities.

[21] Maine (ME), South Maine (SME) and Bangor Hydro Electric (BHE).

[22] ISO-NE, RSP 2007, Table 3-5, p. 28, and ISO-NE 2007 CELT Forecast Data File.

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Figure 8. Proportions of operating company in Each ISO-NE RSP subarea, 2007

		RSP Sub-Areas			
		BHE	ME	SME	NH
Operating Company	BHE	100.0%	-	-	-
	CMP	0.8%	58.4%	37.8%	3.1%
	NH+	-	2.1%	-	79.6%

Source: ISO-NE 2007 Forecast Data File, from the Forecast Report of Capacity, Energy, Loads and Transmission (CELT) 2007 - 2016

As can be seen in Figure 9, the IOU's forecasted load growth trends are much more conservative than the ISO-NE predictions, resulting in a considerable discrepancy in the longer term. In the case of BHE, the difference is more than 450 GWh by 2011 (1,411 GWh from the IOU projection and 1,881 GWh from ISO-NE projection), with ISO-NE projecting much higher demand growth trends.

In order to establish a conservative view on the state's supply-demand situation, we have primarily relied on the ISO-NE's load growth estimates in this report; however, in any cost-benefit analysis of actual investment options, we would recommend analyzing a high and low range around these forecasts.

Figure 9. Growth rate forecasts for energy consumption and peak demand, divided by RSP subareas and IOU service territories, 2007-2016

Affected Area		CAGR (%)			
		Energy Load		Peak Demand	
		2007-11	2012-16	2007-11	2012-16
ISO	BHE	1.30	1.03	1.92	1.18
	ME	1.40	1.37	1.60	1.68
	SME	1.06	1.33	2.10	1.64
	Maine Average	1.41	1.33	2.08	1.57
IOU	BHE	-1.97	-	-	-
	MPS	0.50	0.50	0.50	0.50
	CMP	0.48	-	1.37	1.97

Source: Forecast data from ISO-NE 2007, BHE, MPS and CMP

In terms of peaking season, ISO-NE predicts a summer peaking season for all three subareas on a weather normalized basis under its 50/50 baseline, except for the period 2007-2011 in the ME sub-zone. Among the IOUs, CMP predicts a summer peaking season for the next fifteen years, while MPS forecasts a winter peaking season. There was no applicable data available from BHE.

ISO New England

ISO-NE's 50/50 forecast of energy load and peak demand is published in the 2007 Forecast Report of Capacity, Energy, Loads and Transmission ("CELT report"). It is a 10-year forecast of energy growth in each of the six New England states. The general methodology used by ISO-NE for producing state-level energy forecasts was to regress annual energy by state, against a forecast economic trend variable and forecast electric prices. Binary switches for selected years, to control for unusual events in the data, were used where appropriate. Although the forecast of electric prices was based on the same assumptions as in 2006 (namely that nominal prices were growing at the rate of inflation), the 2007 price forecast included the transition costs from the Forward Capacity Market Settlement Agreement (about $1.2 billion in New England in 2007) and estimates of the capacity costs from the Forward Capacity Market (about $1.9 billion for New England in 2010). Finally, the regional transition and capacity costs were shared among the states based on their share of the actual 2006 summer peak.

Bangor Hydro Electric[23]

Several forecasting assumptions justify Bangor Hydro's findings and their energy load growth forecast of -1.97% per annum. Within the last two years, two of BHE's largest customers from the pulp and paper industry have left the system, one because they went out of business and the other due to self-generation. Additionally, another large (non-pulp and paper) customer has left the grid due the installation of a gas cogeneration plant. At the same time, the demand profiles of BHE customers are not expected to significantly change over the next five years, and changes in immigration patterns to the region are not expected because the largest employment industries are hospitals, social services and government offices, which are all stable sectors. The region has a very low population density and the Bangor Hydro region is itself comparably more rural than CMP's service territory. Finally, as with the other Maine IOUs, BHE's forecasts acknowledge the fact that lumber and pulp and paper sectors in Maine are experiencing an overall decline, bringing down total electricity demand.

BHE's forecast, submitted for their current distribution rate case proceeding, uses ordinary least squares regression analysis. Two econometric regression equations were estimated, one for residential, the other for commercial, based on quarterly sales data from 1989-Q1 through 2006-Q3. Demand-side management program impacts were also accounted for in the model. Finally, these two models estimate kWh, not kW, and a separate industrial forecast (for BHE's roughly 28 largest customers) was done on a per-customer basis. To account for weather impacts, quarterly 15-year averages of both heating degree days ("HDD") and cooling degree days ("CDD") from the National Oceanic and Atmospheric Administration ("NOAA") were used as explanatory variables in the models. These 15-year averages established the baseline for the forecasted years.

[23] The next three subsections are based on communications with representatives of the various Maine IOUs, November 2007.

Maine Public Service

MPS projected a relative low peak demand and energy consumption growth rate of 0.5% per annum. The MPS service territory is not electrically connected directly with the rest of the US, but rather is connected to New Brunswick, Canada, which is then interconnected with the rest of Maine in BHE's service area. The MPS region covers Aroostook Country, the northernmost county in Maine, whose population has been declining for the last several decades according to the U.S. Census and State of Maine Planning Office projections. Its largest city is Presque Isle, with a population of less than 10,000. This rural region is predominantly agricultural and is focused on two industries: lumber and wood, and potato production. There are a few large industrial customers processing either lumber or potatoes, with the largest industrial plant of the largest industrial customer having a maximum monthly hourly demand of 10 MW.

Central Maine Power

Central Maine Power's sales are expected to grow very slowly (0.48% annually) because they have been losing some large lumber and paper industrial customers. A number of buy/sell agreements with large paper companies have recently expired and the mills choose to use their self-generation capabilities to offset purchases from CMP. On the other hand, their 50/50 weather-normalized summer peak growth rate, adjusted for the loss of sales to paper companies, has been growing (1.70% p.a. for 2007-2016) and is expected to continue doing so for some time.

CMP's peak forecast is done primarily for their system planning group. In addition to the forecast for the entire service area, CMP produces peak forecasts for each of 11 service centers within their territory. The forecast methodology allocates kWh sales growth projected to occur in the CMP service area to individual service centers based upon (1) Global Insight's economic forecast for Maine counties and (2) the results of interviews conducted with CMP's largest commercial and industrial customers.

Conclusion

As discussed above, there are some divergences between the ISO-NE and IOU forecasts. Since the ability to compare among the different service areas accurately is important for this report, and given that we are doing a supply-demand survey (which should capture a conservative view of incremental capacity needs), we will be primarily relying on ISO-NE's figures for load growth figures. The use of the utility forecasts would generally suggest bigger surpluses in supply.

2.2 Existing Maine generation

2.2.1 Fuel Mix

As of 2006,[24] the state of Maine had an installed summer capacity of 3,457 MW,[25] representing 11% of the total installed capacity in New England. Figure 10 and Figure 11 below compare the composition of installed generating capacity in Maine versus the rest of New England.

Figure 10. Fuel mix by installed capacity: Maine and the rest of the system, 2007

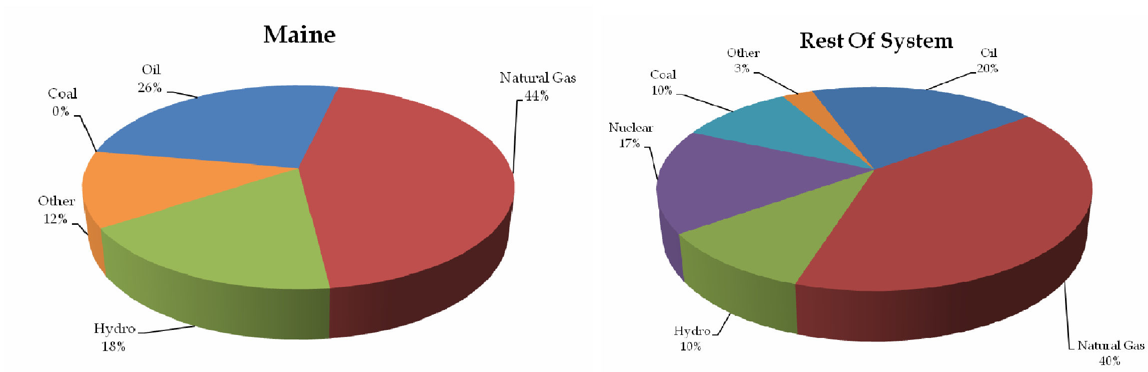
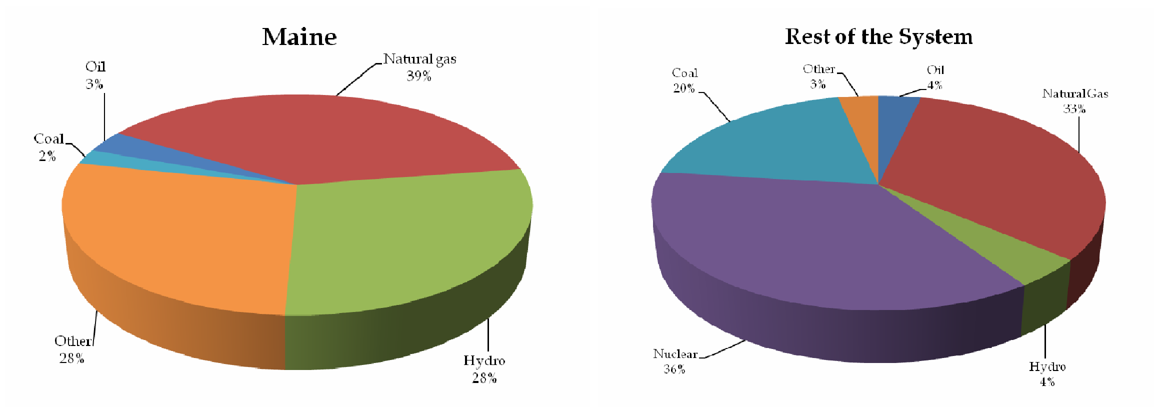


Figure 11. Fuel mix by energy generated: Maine and the rest of the system, 2007



Notes:
- *Maine figures include power plants located in the Maine Power System (which is not part of ISO-NE)*
- *The top charts are based on Summer Claimed Capability measure of capacity*
- *Other category in the charts includes mostly non-hydro renewables*
- *Oil category includes both Distillate and Residual Oil*

Source: *capacity: 2007 CELT; generation: EIA Dec. 2006, http://tonto.eia.doe.gov/state/*

[24] Official 2007 figures will become available in early 2008. We do not expect that the 2007 figures differ substantially from those relied upon in this Report.

[25] ISO-NE CELT report and NMISA's Seven-Year Outlook.

Natural gas is the dominant fuel in the region and in Maine. As shown in Figure 10 above, most of the region's installed capacity is fueled by natural gas and oil, and, in Maine, the dominance of those fuels is even greater. In particular, almost half of the state's installed capacity is fueled by natural gas and a quarter by oil. Given such high dependence on these fuels for generating power, fluctuation in natural gas or oil prices significantly affects Maine's electricity prices. The other sources of fuel for in-state power generation include hydro (18%) and non-hydro renewable energy resources (12%) such as wind, wood, municipal solid waste, and biomass. Unlike the rest of the ISO-NE system, there is almost no coal or nuclear baseload capacity in Maine. Finally, Maine's generation profile (which represents the fuel mix used to produce energy) is more balanced compared to its installed capacity fuel mix. Natural gas, hydro and other non-hydro renewables all equally contribute to the in-state generation mix (although this does not necessarily mean that Maine consumers use this specific generation, since Maine generators are called upon to produce energy on a least-cost region-wide basis by ISO-NE).

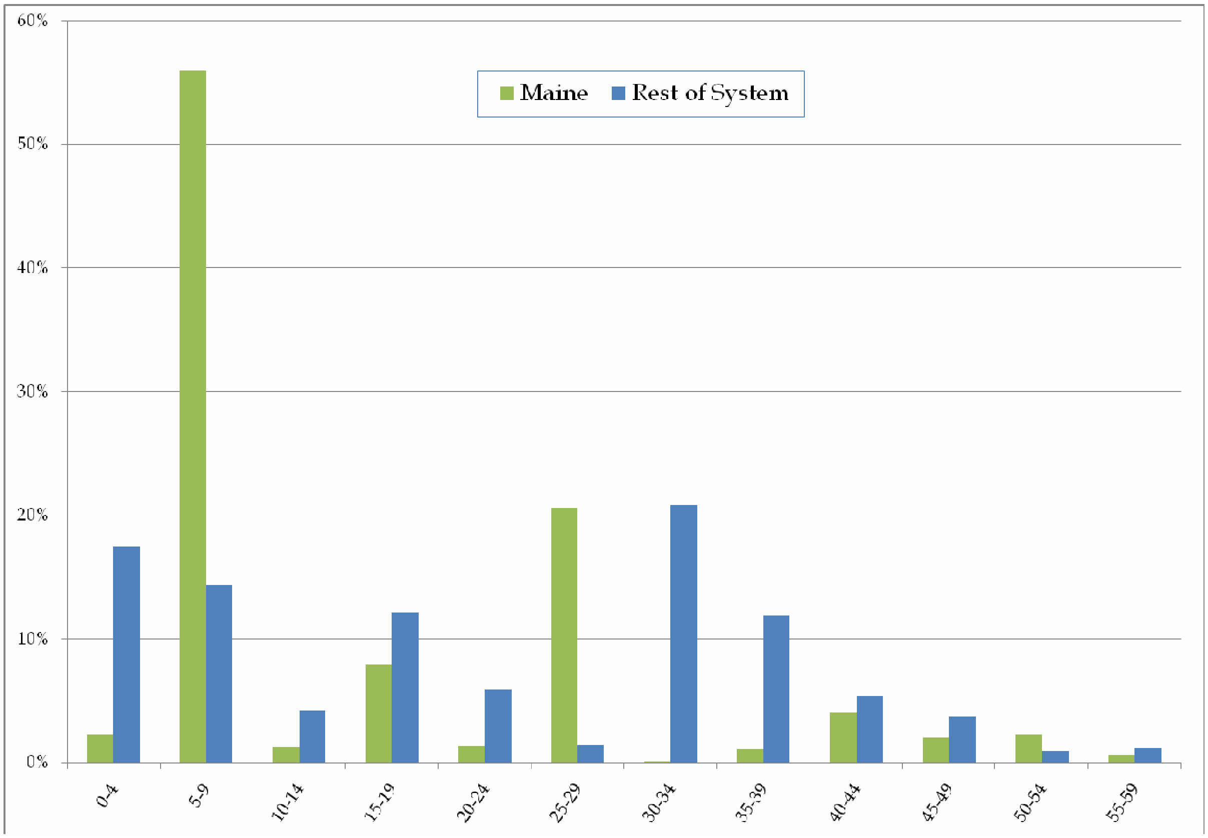
Conversely, a major portion of the rest of the system's output is provided by nuclear (36%), and natural gas (33%) or dual fuel fired plants (4%). Coal is also substantial in the rest of system generation mix, contributing 20% to overall demand. Hydro and other renewables are a small share of rest of system's capacity and a small share of overall generation. It is important to keep in mind that coal and nuclear capacity are typically infra-marginal and therefore do not affect energy prices. Energy prices are set by the oil and gas-fired capacity in many hours.

2.2.2 Age of plants

Figure 12 illustrates the age of plant distribution in Maine and rest of New England. Compared to the rest of the system, Maine has a relatively newer generation fleet. More than half of Maine's power plants in capacity terms – approximately 1,614 MW – are less than 10 years old. Combined cycle plants represent 88% of the installed capacity that is less than ten years old; the rest of the capacity in this age class includes gas combustion turbines or biomass/refuse plants. A fifth of the plants (587 MW) in Maine fall in the 25-29 age group.

On the other hand, only 32% of the capacity in the rest of the New England system is less than 10 years old. The bulk of the capacity is in the 30-34 age range. Almost half of the plants under this age category are gas/oil steam plants and more than 40% are nuclear steam plants. The rest are either oil stream, gas/oil combined cycle or oil internal combustion plants.

Figure 12. Distribution of capacity by age of plant in Maine and the rest of New England



Note: Data excludes hydro; Maine includes Northern Maine. Source: ISO-NE, 2007 CELT Report, NMISA

2.2.3 Location of plants

As shown in Figure 13, almost half (48%) of non-hydroelectric renewable capacity in New England can be found in Maine.[26] Non-hydroelectric renewable energy includes wind, solar thermal, photovoltaic energy, wood, wood waste, municipal solid waste, other biomass and geothermal. In addition, Maine has the largest hydroelectric capacity (37% with 719 MW) among the other states in the region.[27]

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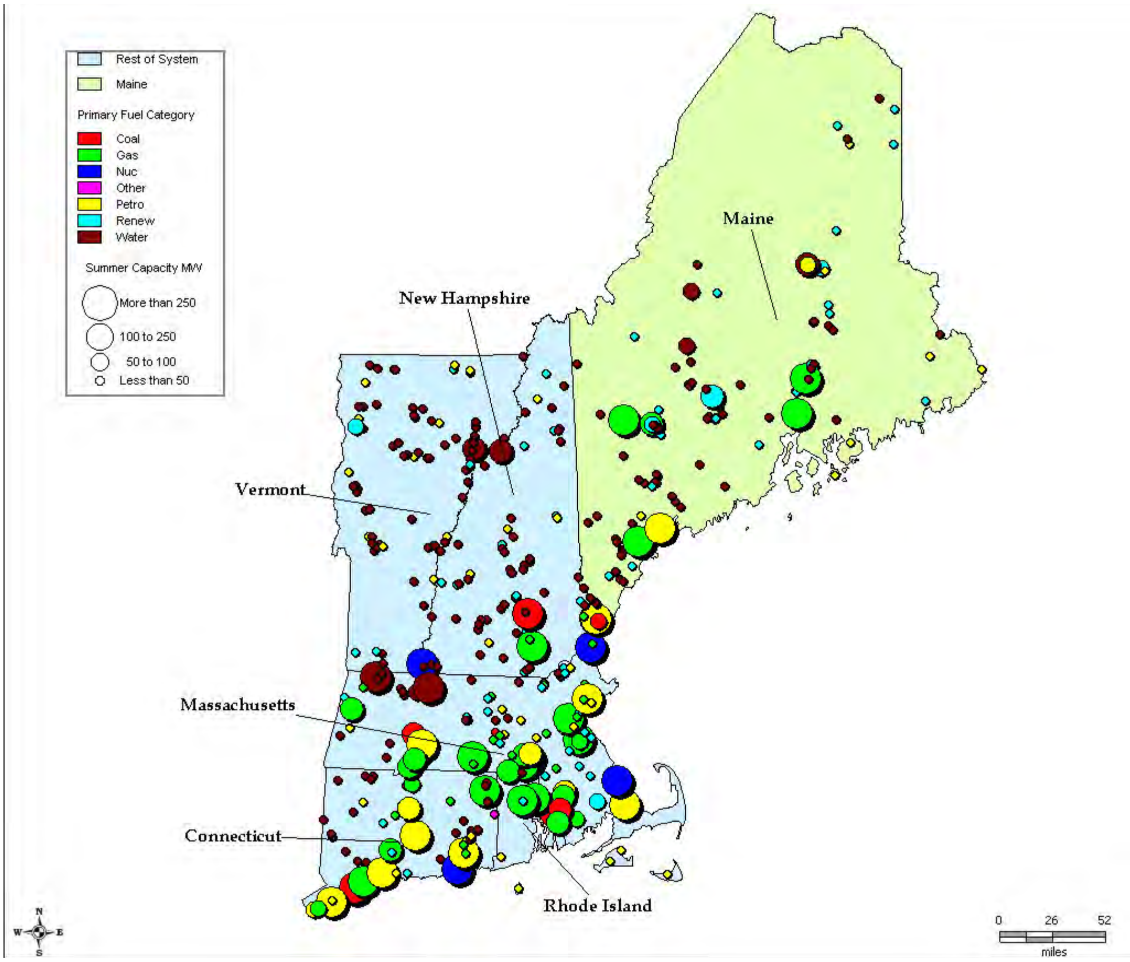
[26] Based on the EIA 2006 summer capacity, Maine has a capacity of 699 MW of renewable energy, representing 48% of the total renewable capacity in New England.

[27] The total hydro capacity in the region in 2006 was 1950 MW, with 26% (or 512 MW) coming from New Hampshire, 16% (or 309 MW) from Vermont, 13% (or 259 MW) from Massachusetts, and 8% (or 147 MW) from Connecticut. Data is from the Energy Information Administration. Available online at http://www.eia.doe.gov/cneaf/electricity/epa/existing_capacity_state.xls.

Figure 13. Map of existing generation plants in New England by size and fuel



Source: Energy Velocity, 2006 Data

It should be noted that Maine and Rhode Island are the only states in the region that do not have nuclear plants. Most of the power plants in New England are fueled by natural gas with almost half of the region's total capacity concentrated in Massachusetts. Petroleum-fired plants are mostly located in Connecticut and Massachusetts. Finally, coal, which comprises a tenth of the total capacity of the region's fuel mix, is more prevalent in Massachusetts than in the other states in the region.

2.2.4 Historical production from Maine and New England plants

Figure 14 below compares average annual capacity factors of relatively new Combined Cycle Gas Turbines ("CCGTs") in Maine and their peers in rest of New England over the last three years. The average capacity factor of a group of selected CCGTs in Maine built after 2000 has been falling for a few years since 2004, although the trend is the result of plant specific factors.

Figure 14. Additional information on selected CCGT plants, 2004-2006

	Plant Name	RSP Zone	Summer Capacity 2006 (MW)	Commercial Online Year	Tested Heat Rate Fully Loaded (Btu/kWh)	Average Capacity Factor (%)		
						2004	2005	2006
MAINE	Maine Independence Station	BHE	490	2000	6,828	60 92%	60 55%	48 51%
	Rumford Power Associates	ME	254	2000	7,119	72 63%	44 58%	20 77%
	Westbrook Energy Center	SME	506	2001	7,001	73 70%	79 58%	75 30%
REST OF SYSTEM	Lake Road Generating Plant	RI	709	2002	6,878	35 19%	42 98%	61 48%
	Milford Power Project	SWCT	493	2004	7,186	51 92%	66 08%	68 31%
	ANP Bellingham Energy Project	RI	442	2002	7,319	29 33%	39 68%	51 04%
	ANP Blackstone Energy Project	RI	441	2001	7,074	25 02%	39 16%	74 31%
	Fore River	SEMA	668	2003	6,895	23 97%	28 16%	40 70%
	Kendall Square Station	Boston	208	2002	6,998	21 15%	77 33%	76 76%
	Millennium Power	WMA	325	2001	6,748	36 02%	50 01%	56 36%
	Mystic	Boston	1360	2003	6,758	65 53%	58 90%	83 59%
	Granite Ridge	NH	797	2002	6,748	37 16%	59 03%	46 84%
	Newington Power Facility	NH	530	2002	7,025	52 61%	53 86%	55 71%
	Rhode Island State Energy (FPLE)	RI	515	2002	7,009	19 18%	50 52%	60 75%
	Tiverton Power Plant	SEMA	250	2000	7,018	82 50%	81 06%	38 40%

Source: Energy Velocity – Environmental Protection Agency – Continuous Emission Monitoring System (EPA-CEMS)

Rumford Power in Maine and Tiverton Power in Rhode Island showed a significant drop of capacity factor in 2005 and 2006. These two plants were actually shut down in November 2005 and February 2006, respectively.[28] They were owned by Philip Morris Capital Corp ("PMCC") and were being operated by Calpine under a lease agreement with PMCC through 2030. However, Calpine, which filed for bankruptcy in December 2005, ran into financial trouble and these plants have been idle and in a "forced outage" pending a change in management control. Calpine eventually walked away from the leases.[29]

Aside from Rumford Power in Maine and Tiverton Power in Rhode Island, selected CCGTs in Maine showed a stable capacity factor, while CCGTs in the rest of New England exhibited a rising trend in average capacity factor levels. There are no significant heat rate differentials between selected CCGT in Maine versus rest of system; therefore, the differences in operation are not significantly related to differences in technology efficiencies. Rather, Maine generators have been affected by transmission constraints, which at certain times have limited their access to southern New England markets. A good example of this is Maine Independence Station, a relatively new CCGT baseload plant that exhibited a decreasing average capacity factor between 2005 and 2006. At the same time, CCGTs in other parts of New England have seen a rising demand for their output. The nodal prices received by Maine's CCGTs versus those of the CCGTs in other parts of New England are significantly different, as shown in the Figure 15.

[28] FERC; Docket No. EC06-122-000; Order Authorizing Acquisition of Facilities; June 19, 2006.

[29] In the March 6, 2006 *Megawatt Daily* publication, Calpine was quoted in citing "skyrocketing gas prices and other market problems" as the basis for its decision to close operations at these facilities.

Maine CCGTs' nodal prices are close to their zonal average, while the nodal prices of the Mystic plant and Milford Power Project are lower than their respective zonal average, suggesting that these plants exhibited lower cost on average than other local generation.

Figure 15. Zonal and nodal (unit) LMP for selected CCGTs in New England

Plant Name	RSP Zone	2005 Zonal RT LMP Price ($/MWh)	2005 Unit RT LMP Price ($/MWh)	2005 Diff between Zonal and Nodal	2006 Zonal RT LMP Price ($/MWh)	2006 Unit RT LMP Price ($/MWh)	2006 Diff between Zonal and Nodal
Maine Independence	BHE	$70.4	$70.1	-$0.2	$56.1	$54.9	-$1.1
Westbrook	SME	$70.4	$71.1	$0.7	$56.1	$56.6	$0.5
Milford Power Project	SWCT	$80.2	$77.3	-$2.9	$64.5	$60.5	-$4.0
Mystic	Boston	$77.0	$76.3	-$0.7	$60.4	$59.3	-$1.1

Source: Energy Velocity – Environmental Protection Agency – Continuous Emission Monitoring System (EPA-CEMS)

Furthermore, if we look at Maine only, Westbrook has a very stable capacity factors (approximately 75% between 2004 and 2006) while the capacity factor for Maine Independence Station has dropped from 60% in 2005 to less than 50% in 2006. This can be further validated by the fact that the unit LMPs (or nodal prices) for the Maine Independence Station were lower than those for Westbrook, due to the more negative marginal losses and congestion components at the Maine Independent Station node, suggesting rising local transmission constraints.

2.3 Demand response programs

It is important to look at the evolution of demand response programs in Maine, since Demand Response ("DR") has the potential of enhancing electric system reliability by reducing peak demand and delaying the need for infrastructure investment. To date, there have been three ISO-NE real-time reliability-based DR programs that have affected Maine: (1) the real-time two hour DR program, (2) the real-time 30-minute DR program, and (3) the profiled response program. Figure 16 shows that Maine has the second largest two-hour DR capacity in New England, with a summer capacity of 10.8 MW or 29% of the New England-wide capacity. For the real-time 30-minute DR, 10% of the region-wide assumed capacity, or 123.9 MW, comes from Maine (see Figure 17). Additionally, Maine has a profile response program with a total DR capacity of 11 MW and a 78% performance rate.[30]

There are also two more DR programs in New England, which are not covered in the 2007 RSP: Day-ahead load response and Real-time price response programs. To date, in spite of lower LMPs, the level of participation in these programs by Maine participants has been higher as a percentage of the state's peak demand than that of other states in New England. As of August 2007, Maine had 199 MW of such DR available compared to 1,149 MW total for the entire New

[30] ISO-NE, RSP 2007, page 38.

England system, representing 17% of the DR in the region. In contrast, the 2007 peak demand forecast for Maine represents only 7.4% of the 2007 peak demand forecast for New England.[31]

Figure 16. Real-time 2-hr demand response

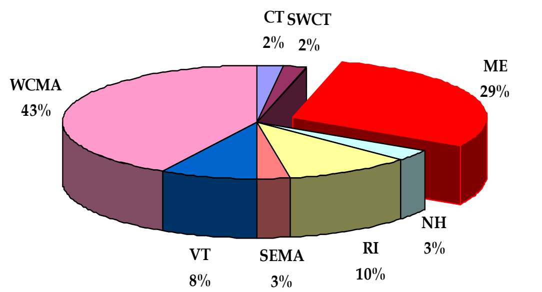
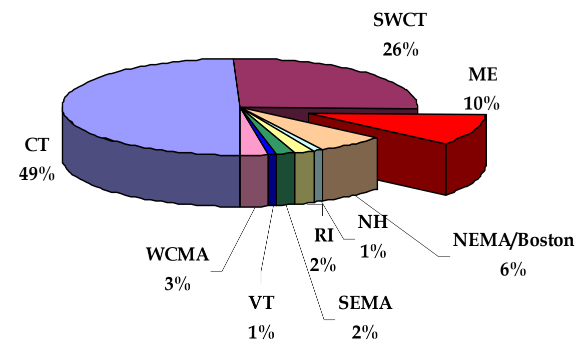


Figure 17. Real-time 30-min demand response



Under the Forward Capacity Market, customers who bid their load reduction capabilities in a forward capacity auction will be able to compete directly against supply-side resources, and set the auction price.[32] All of the programs mentioned above, except for the RT Demand Response 30-minute program, are expected to be terminated once the FCM is operational in June 2010, as ISO-NE expects that these demand resources would be interested in directly participating in the FCM as "Demand Resources".[33] The RT Demand Response 30-mimute program will also be eligible for capacity payment and will therefore presumably also bid in the FCM.

According to a November 2007 report commissioned by the MPUC, Maine is expected to have one of the highest levels of DR in the country by June 2010, with an expected DR quantity of about 377 MW in the first year of the new FCM, representing approximately 17.5% of the ISO-NE forecast peak demand for Maine in 2010 (compared to an average of 11% for the rest of the New England system).[34]

Given the similar treatment that demand-side resources (including both peak demand response and energy efficiency, as discussed in footnote 6 on page 8) and supply-side resources (conventional generation) are expected to receive in the FCM, additional demand-side resources – if of significant volumes – could reduce capacity clearing prices from levels that would have otherwise occurred in the Forward Capacity Auction. Lower energy consumption level also results in lower energy cost to load from the State's perspective. In addition, if Maine has

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[31] Synapse, Increasing Demand Response in Maine, Draft Report, November 2007.

[32] U.S. Department of Energy, Federal Energy Management Program, http://www1.eere.energy.gov/femp/program/utility/utilityman_em_me.html

[33] *See* ISO-NE Market Rule 1, Section III.13.1.4.

[34] Synapse, Increasing Demand Response in Maine, Draft Report, November 2007

relatively more demand-side resources(either peak demand response or energy efficiency, which impacts electricity consumption for more hours than just the peak) than other states in New England, measured as demand response in MW divided by peak load, then Maine would enjoy a lower capacity cost to load due to declining peak load share, which is the defining cost allocation metric used by ISO-NE in the FCM settlement process. A more detailed discussion of how demand-side resources affect the peak load share and FCM costs can be found in Section 4.4 of this Report.

Through reductions in energy demand during peak hours, demand-side resource programs can also reduce energy market prices, if the reduction in demand is significant enough to move the price-setting point down to a lower cost offer on the supply curve. If this reduction in energy demand persists over a long enough period of time, demand-side resource programs can also reduce the need for additional generating facilities to meet forecasted demand. The November 2007 study mentioned above concludes that energy efficiency projects that reduce load across all hours will have an approximate 1-to-1 downward impact on prices in the Real-Time market for the first three years (i.e., a 1% reduction in hourly load will reduce Real-Time hourly energy market prices by 1%).[35,36] Applying this 1-to-1 projection results in a need for 160 MW of incremental conservation programs across New England to reduce LMPs by $0.75/MWh on average (which is 1% of an average energy price level of $75/MWh).[37] Thus, as is the case with new supply resources, hundreds of MW of energy efficiency reductions are necessary to have any meaningful impact on market clearing prices.

2.4 Historical supply-demand balance

In addition to the difference in terms of fuel mix and generation, supply-demand balances between Maine and New England are also very different. For the past three years, Maine enjoyed an average internal reserve margin[38] of 52.8%. The state's supply-demand conditions are illustrated by the ratio of net capacity to peak load in Figure 18.

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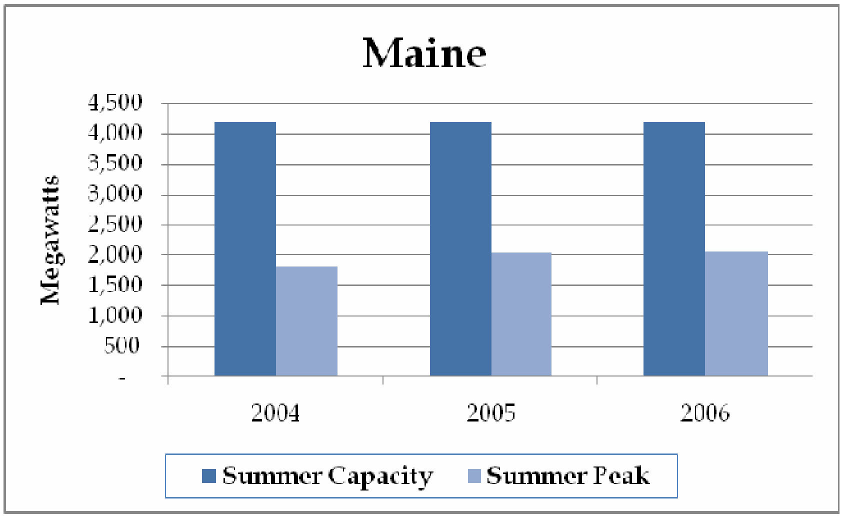
[35] In the medium-term, the study projects a 1-to-0.5 relationship (i.e., a 1% reduction in hourly load will reduce Real-Time hourly energy market prices by 0.5%).

[36] ISO-NE's 2006 RSP also suggested similar conclusions (note that ISO-NE's Scenario Analysis was based on a number of simplifying assumptions). According to ISO-NE's 2006 RSP and the Scenario Analysis completed that year, the addition of 1,000 MW of price-taking baseload resource, such as a nuclear unit, would decrease the annual wholesale electricity price by 5.7% system-wide. Adding an additional of 1,000 MW new-technology coal would decrease the annual wholesale electricity price by 5.6%. The addition of a 5% on-peak conservation project (a 5% reduction of load from 7:00 a.m. to 11:00 p.m. on weekdays) would reduce the annual wholesale electricity prices by 4.7%. In contrast, the addition of 500 MW of incremental load response activated during on-peak hours when LMPs exceed $150/MWh would reduce the annual wholesale electricity price by only 0.02%..

[37] The average hourly load in New England for the next 10 years is 16,000 MW. Therefore, 1% reduction in hourly load in New England is 160 MW (=1%*16,000 MW).

[38] The internal reserve margin is the proportion of unused available capacity of an electric power system during the peak load of a utility or geographic area over the total capability of the system.

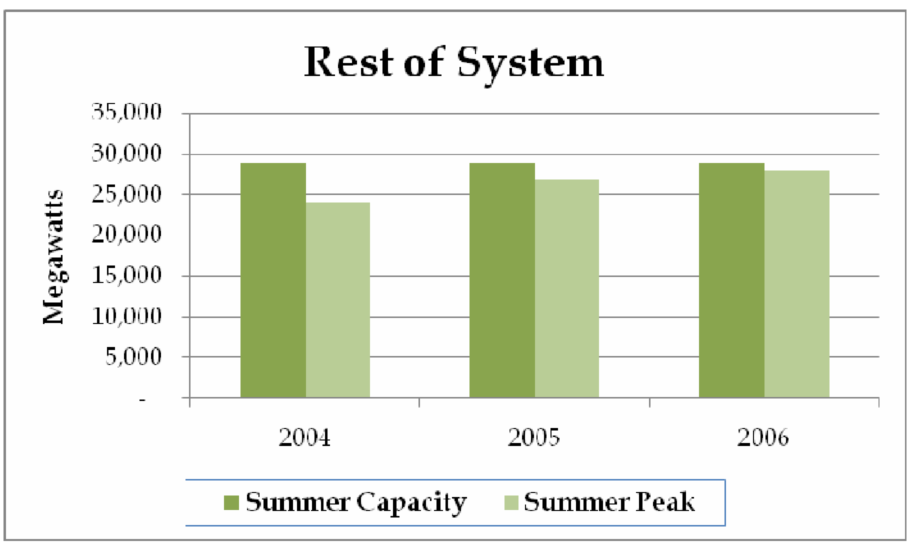
Figure 18. Net summer capacity and summer peak in Maine, 2004-2006



Source: capacity: EIA Electric Power Annual 2006 - Data Tables; summer peak: ISO-NE 2007 Forecast Data.

In comparison, the rest of the ISO-NE system has experienced a relatively tight internal reserve margin of 9.0% for the past three years. This difference in supply-demand conditions is also illustrated by the ratio of net capacity to peak load in Figure 19 below.[39]

Figure 19. Net summer capacity and summer peak in the rest of New England, 2004-2006



Source: capacity: EIA Electric Power Annual 2006 - Data Tables; summer peak: ISO-NE 2007 Forecast Data.

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[39] Please note that the scale for Figure 19 is different from that used in Figure 18.

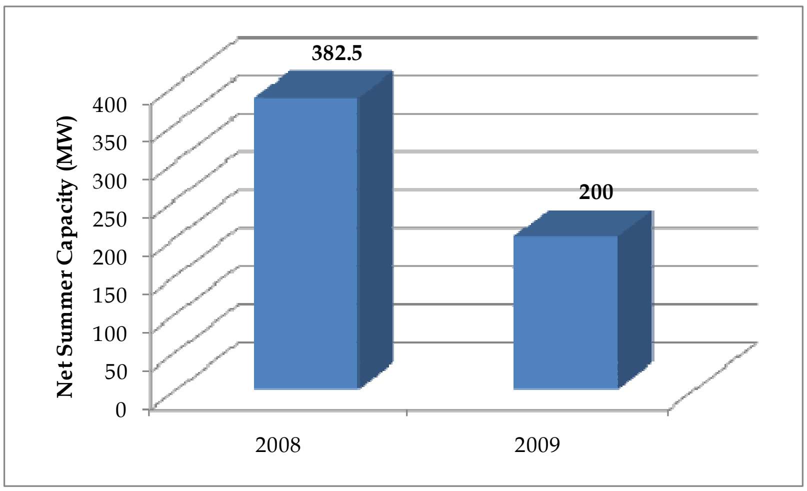
A comparison of Figure 18 to Figure 19 underscores the fact that Maine has had much more generation capacity than necessary to meet its load (although the gap is decreasing) as opposed to rest of New England, where there is very little surplus capacity over summer peak load.

2.5 Announced new entry and retirement

2.5.1 New entrants

Based on the most recent ISO-NE Interconnection Request Queue, a total of 582.5 MW of new capacity is proposed in Maine due to come online by 2009; this capacity is exclusively from wind projects.[40] As shown in Figure 20, more than half (66%) of this proposed generation is planned to be online by 2008.

Figure 20. Proposed new capacity, 2008-2009



Note: Data does not include proposed plants in Northern Maine or the proposed Oxford and Wyman hydro plants.
Source: Interconnection Request Queue, as of January 2008

In Northern Maine, two proposed projects are currently under study through the MPS' Large Generation Interconnect Procedure. These two projects are the Aroostook Wind Energy and the Loring Bio-Energy Gas Turbine.

The Aroostook Wind Energy could produce up to 500 MW once complete (three phases are planned: 100 MW, followed by another 150 MW and then an additional 250 MW).[41] An initial phase of the project is projected to be online by 2008, if the development goes forward. The

[40] It is likely that permitting issues, transmission constraints and other barriers to investment will delay or even deter some of the proposed capacity from reaching commercial operation, as scheduled. However, the announced figure is still useful information and is presented in this report on an indicative basis as a tangible point of reference for this study.

[41] NMISA, Seven-Year Outlook, page 4.

owners of the project are currently in an exploratory phase, securing specific sites for the generation plant.[42]

The Loring Bio-Energy ("LBE") project has been licensed to produce approximately 55 MW of electric power during the summer and 70 MW during the winter. It is being planned to be located at the former Loring Air Force Base in Limestone, Maine.[43] Owned by Loring BioEnergy LLC, the LBE project was preliminarily licensed for a new combustion turbine, combustion turbine generator, duct-fired heat recovery steam generator, and a steam turbine generator to produce electric power and process steam for sale. This project was initially delayed due to design changes with their fuel mix (currently, the developers are projecting to employ biofuel and natural gas). Although there still are several key development milestones to be attained, the developer has stated that the current schedule aims for the plant to be online in the first quarter of 2010.[44]

2.5.2 Announced retirements

Although the retirement of existing supply resources is always a potential concern, as of November 2007, there have not been any official announcements of plant retirements in Maine.[45] Indeed, in all of the planning reports produced by ISO-NE or NIMSA, the primary assumption is that there will be no retirements over the modeling timeframe.[46] The sole exception is the current initiative underway in the BHE sub-area, where a group of conservation interests is seeking to buy three hydroelectric plants[47] from PPL Corporation in order to dismantle the projects to allow for the restoration of the Penobscot River. The dams, totaling 18 MW of electricity generating capacity, will likely be removed once their purchase is complete and all the necessary regulatory approvals are acquired. The dismantling is planned for sometime around 2008-2010.[48]

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42 *See* CLF Ventures website at http://www.clfventures.org/practice_wind.html

43 Air Emission Application to the Bureau of Air Qualify, available at http://www.maine.gov/dep/air/licensing/Ch115Licenses/A880CM.pdf

44 The information on the Loring Bio Energy Gas Turbine is obtained from a telephone interviews with Mr. Hayes Gahagan, Loring Bio Energy local developer, November 2007 and January 2008.

45 According to ISO-NE Market Support Services, the retirement process in ISO-NE differs slightly depending on whether the generator is in excess of 5 MW or not: If it is, it has to go through a formal examination in order to determine whether the plant's retirement would cause a reliability problem for the grid, whereas smaller plants generally get their requests approved without such a process. Ultimately, the customer then submits a Generator Asset Registration form stating the formally approved retirement date and requesting that the generator be retired from the markets. That submission then starts the internal ISO process to remove the unit from all ISO databases for the requested effective date, triggering official announcements to the system.

46 ISO-NE, RSP 2007, page 2.

47 These include the Veazie (8 MW), Great Works (8 MW) and Howland (2 MW) Dams.

48 Bangor Daily News, "Penobscot River restoration groups near funding goal", October 23, 2007; PPL Corp, October 6, 2003 Press Release; Penobscot River Restoration Trust at www.penobscotriver.org.

2.6 Implications of environmental policies on existing generation

As mentioned in ISO-NE's RSP 2007, new proposed state, regional and federal environmental regulations have the potential to directly affect system reliability, electricity production, regional air emission levels and essentially every aspect of the energy market in New England. These policies (which we discuss in more detail below), scheduled to be implemented over the next 10 years, will affect the generation of electricity by fossil fuels as well as by renewable resources and potentially nuclear plants.[49]

2.6.1 Overview of environmental regulation and requirements affecting Maine resources

Two important environmental policies and regulations are currently being implemented that have implications for Maine: a recently-enacted modification of the states' Renewables Portfolio Standards ("RPS") and the Regional Greenhouse Gas Initiative ("RGGI"). A third significant environmental regulation, the U.S. Environmental Protection Agency Clean Air Interstate Rule ("CAIR"), is not expected to directly affect the state of Maine.

An RPS is a state-specific requirement on electric utilities and other electric suppliers to supply a minimum percentage or amount of their load with eligible sources of renewable energy.[50] This percentage typically increases annually up to a specified level. The RPS is intended to stimulate the development of new renewable resources and achieve a more diverse and "clean" generation portfolio.[51] Maine, along with several other New England states, has an RPS.

In 1999, the MPUC adopted rules for the state's Renewable Resource Portfolio Requirement, requiring each competitive electricity provider, including standard offer providers, to supply at least 30% of their total retail electric sales in Maine using electricity generated by eligible renewable resources and certain efficient resources. Unlike most other state RPSs, the Maine RPS allows electricity generated by efficient combined heat and power ("CHP") systems and other systems that qualify as "small power production facilities" under the federal Public Utility Regulatory Policies Act of 1978 ("PURPA") to be eligible. In June 2006, Maine created another renewable portfolio goal to increase new renewable energy capacity by 10% by 2017 (gradual increase of 1% per year). Unlike the original 30% standard, municipal solid waste facilities and CHP systems, previously qualified under PURPA, are no longer eligible under the new renewables objective, and hydropower facilities must meet all state and federal fish passage requirements.[52]

The qualifications for other states' RPS differ from those in Maine, as well as the target requirements. Figure 21 compares Maine's RPS requirements to those from other states.

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[49] ISO-NE, RSP 2007, page 57.

[50] US DOE Energy Efficiency and Renewable Energy.

[51] ISO-NE, RSP 2007, page 63.

[52] Database of State Incentives for Renewables & Efficiency ("DSIRE"), October 2007.

Generally speaking, resources in Maine can be used to meet other neighboring states' RPS.[53] However, in some cases, resources that would not qualify in Maine for renewable energy credits ("RECs") per the RPS, are able to qualify in other states. One example of this is CHP systems, which qualify in Connecticut for RECs, but do not qualify in Maine under the new capacity-oriented RPS.

Figure 21. RPS requirements from other states

State	Amount	Year		State	Amount	Year	
Arizona	15%	2025		New Hampshire	22-25%	2025	(4)
California	20%	2010		New Jersey	22.50%	2021	
Colorado	20%	2020		New Mexico	20%	2020	
Connecticut	27%	2020	(1)	Nevada	20%	2015	
DC	11%	2022		New York	24%	2013	
Delaware	20%	2019		North Carolina	12.50%	2021	
Hawaii	20%	2020		Oregon	25%	2025	(5)
Iowa	105 MW	-		Pennsylvania	18%	2020	
Illinois	25%	2025		Rhode Island	16%	2020	(6)
Massachusetts	4%	2009		Texas	5,880 MW	2015	
Maryland	9.50%	2022	(2)	Vermont*	10%	2012	(7)
Maine	30%+10%	2017	(3)	Virginia*	12%	2022	
Minnesota	25%	2025		Washington	15%	2020	
Missouri*	11%	2020		Wisconsin	10%	2015	
Montana	15%	2015					

*Notes: Percentages refer to a portion of electricity sales and megawatts (MW) to absolute capacity requirements. Most of these standards phase in over years, and the date refers to when the full requirement takes effect. * Three states, Missouri, Virginia, and Vermont, have set voluntary goals for adopting renewable energy instead of portfolio standards with binding targets.*

Source (unless otherwise specified): U.S. Department of Energy, Energy Efficiency and Renewable Energy ("EERE"), EERE state activities and partnerships, last updated June 2007. Other sources: (1) Connecticut Department of Public Utility Control; (2) DSIRE, Tier 1 only; (3) DSIRE; (4) "RPS Passes New Hampshire House by Wide Margin", April 6, 2007, renewableenergyaccess.com; (5) DSIRE, 25% for large utilities, 10% small, 5% smallest; (6) DSIRE; (7) DSIRE.

RGGI is a cooperative effort by ten states involved in the design of a regional cap-and-trade program covering carbon dioxide emissions from power plants in the Northeastern region.[54] It is part of a regional strategy to control emissions and reduce the region's contribution to global greenhouse gas emissions. The initiative will require electric power generators in participating

[53] Note however that other states' RPS may impose plant size and fuel type limitations that could limit the ability of Maine's renewable resources to sell into another state's program.

[54] States participating in RGGI include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont.

states to reduce their carbon dioxide emissions. This will be implemented through a multi-state cap-and-trade program with a market-based emissions trading system for carbon dioxide allowances.[55] The first compliance period under RGGI will begin in January 2009 and will be based on a multi-year period. The goal is to stabilize carbon dioxide emissions from electric power plants in the Northeast at their 2000-2004 four-year average. This first phase will last until 2014, after which time the goal will be to reduce emissions by 10% by 2019.[56] Although the CO_2 allowance price has not been fixed yet, many ISO-NE planning documents assume a cost of $5/ton, at least in the initial stages of RGGI.[57]

All fossil fuel-fired electricity generating units with a nameplate capacity larger than 25 MW will potentially be affected. In addition, smaller generation units associated with a main unit (such as a waste heat or combined cycle steam generator) are likely to be affected in the future, if and when allocation to units on an electricity output-basis is considered.[58]

Thanks to Maine's relatively 'cleaner' generation fleet, its energy may become more competitive over time because of limited negative impact from environmental regulations and CO_2 allowances additional costs. However, exports to the rest of New England from these relatively 'cleaner' resources will likely be constrained at certain times unless transmission reinforcements occur.

2.6.2 Impact of RPS on Maine

In terms of percentage of energy that needs to come from renewable sources (30%), Maine's RPS is one of the most ambitious in the United States, but this number is actually lower than it seems due to the fact that electricity generated by efficient CHP systems, biomass and other small (distributed) power systems are eligible under Maine's RPS. The required percentage of renewables is in fact lower than the existing percentage of renewable energy currently produced in Maine[59] and the low RECs prices in Maine reflect the relative abundance of qualified resources. As shown in Figure 11 on page 21, a total of approximately 56% of Maine's load was supplied by RPS-eligible resources (hydro and non-hydro renewables such as biomass) in 2006.[60] This figure indicates that Maine will be easily capable of meeting its energy-

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[55] It is expected that the proceeds generated from auctioning these allowances will benefit the Energy and Carbon Savings Trust, a portion of which will be spent on electric energy efficiency programs. *Source: Maine Revised Statutes, §10008, Sec.11.35-A.*

[56] Maine Department of Environmental Protection, FAQs on Maine's Regional Greenhouse Gas Initiative Law of 2007 and administrative rules proposed to implement it, August 2007

[57] ISO-NE, *Environmental Issues in System Planning*, NARUC Summer Meeting on July 15, 2007

[58] RGGI, Draft Lists of Electric Generating Units Potentially Subject to RGGI Program, www.rggi.org

[59] DSIRE, Oct. 2007

[60] The Maine PUC found that generation from hydro and non-hydro renewables reached 47% of total electricity generated in 2006. The discrepancy between the different data sources could stem from either the issue in different definitions of the service areas, as described in Section 2.1.4, or from different definitions of 'non-hydro renewables'.

based RPS requirements. The new capacity-based renewables requirement instituted in 2006 is likely to be more constraining, as it sets the requirement for RPS on a new capacity basis and is stricter in eligibility of resources. Nevertheless, ISO-NE projects that by 2016, the new renewable capacity sources in Maine could generate up to three times the annual electric energy required to meet Maine's upgraded RPS requirement (30%+10%). However, some or all of the new development may not be available to serve load in Maine. Rather, it may be exported and sold to the rest of the region, which is expected to experience RPS-related demand in excess of supply. It is notable that other states in New England also have substantial RPS standards and REC trading forums. Depending on the local market dynamics, Maine renewables may be incentivized economically to qualify and sell their renewable attributes into another state's program.

More generally, as a result of the state RPSs and RGGI, all of New England is going to require the development of new renewable resources to meet their goals.

2.6.3 Impact of RGGI on Maine

Although RGGI rules are state-specific, the allowance market encompasses the entire region. More importantly, RGGI impacts specific types of generation. Those generators that have a relatively large carbon footprint – such as coal and oil-fired generation – are more affected than low carbon emitters, such as gas-fired plants. Furthermore, it is important to keep in mind that depending on overall efficiency, some units may have smaller footprint than others within the same technology or fuel bracket. According to the Model Rule that dictates the terms of state participation, the near term goal is to stabilize emission at current levels by 2014, but states are individually responsible for setting budgets for its resources that come under the requirements of this CO_2 program.

Most of the "impact" of RGGI will be through cost pressures, either direct cost increases due to allowance purchases or indirect cost pressures through production reductions (to reduce carbon emissions). Renewables, such as hydro and wind power plants, will not feel any cost pressures from RGGI, and may in fact benefit from RGGI-related increases in market clearing prices.

ISO-NE's 2007 RSP mentions that even with stronger conservation and energy-efficiency measures and the addition of low- or zero-emitting baseload generation, "meeting New England's allocation of RGGI's carbon dioxide cap will be a challenge for the generators affected by RGGI."[61] In addition, ISO-NE projects that the cost of buying RGGI allowances and offsets will likely be reflected in the wholesale electricity markets, with carbon emission caps and trading effectively increasing marginal costs of fossil fuel based resources. Maine will experience a different RGGI impact from the rest of New England only to the extent that Maine is congested from rest of system, and a lower emission resource sets Maine's LMPs.

The Maine Department of Environmental Protection expects a one-time increase in retail rates directly related to the price paid for the RGGI allowances. For example, if, as mentioned above, allowances cost $5 per ton of carbon dioxide, the average energy price increase is expected to be

[61] ISO-NE, RSP 2007, page 7.

0.25 cents per kWh or $2.50/MWh. If however allowances in the long-run cost $10 per ton of carbon dioxide, the price effect will be 0.5 cents per kWh, or $5/MWh, amounting to a 3% or $30 increase on an annual bill for the average residential customer.[62]

Figure 22 below shows the electric power producers in Maine currently subject to the RGGI law. The potential impact of RGGI to Maine's LMPs depends on how and when these plants operate, the impact of transmission constraints, and what type of resources are setting LMPs in Maine. If the plant is running as a baseload resource (for example, Westbrook, Rumford, and Androscoggin), it is very likely that it will be infra-marginal (a price-taker), and another resource will be setting price, most likely a more expensive resource somewhere else in New England.

In general, given the carbon content of gas-fired versus oil-fired resources, we expect that on-peak prices may rise more than off-peak prices, particularly if transmission constraints between Maine and New England result in oil-fired resources setting LMPs. Typically, when Maine is constrained from rest of New England on-peak, more expensive, less efficient resources are setting price in rest of New England. Although the carbon content of oil may be the same between two oil-fired plants, a relatively less efficient plant will emit more carbon and will have to secure more allowances, holding all else constant. Therefore, we expect that Maine may face a relative comparative advantage in RGGI impact on-peak during constrained hours.

During off-peak hours, when constraints between Maine and New England are more limited, the price-setting resource is likely to be a gas-fired combined cycle plant (and is likely to continue to be gas-fired resource in the future). Gas-fired plants have a substantially smaller carbon footprint as compared to oil- and coal-fired capacity, and therefore we expect that off-peak LMPs in Maine will rise by a smaller amount in off-peak hours than in on-peak hours.

Figure 22. Electric power producers in Maine subject to RGGI law

- FPL Energy Maine, Inc. – Yarmouth
- Calpine – Westbrook
- Rumford Power – Rumford
- Verso Paper – Androscoggin
- Verso Paper – Bucksport
- Casco Bay Energy – Veazie.

Source: Maine Department of Environmental Protection, FAQs on Maine's Regional Greenhouse Gas Initiative Law of 2007 and administrative rules proposed to implement it, August 2007

2.7 Conclusions and recommendations

Having reviewed many aspects of energy demand and supply in New England (both historical and forecasted), we can draw a number of informative conclusions regarding the state of the existing infrastructure and future needs in Maine.

[62] Maine Department of Environmental Protection, FAQs on Maine's Regional Greenhouse Gas Initiative Law of 2007 and administrative rules proposed to implement it, Aug. 2007

In terms of energy pricing and demand, Section 2.1.2 has shown that both Maine and New England have experienced an increase in nominal prices of electric energy for customers for at least the last fifteen years (in real terms, Maine's prices have actually been decreasing while New England's prices experienced a slight increase). It is also worth noting that both regions' annual peaks are growing much faster than their energy consumption. As explained in Section 2.1.1, this is likely due to an increase in air-conditioning penetration, as its use is concentrated during peak hours.

In terms of generation capacity, Maine has much more generation capacity than necessary to meet its load, as opposed to the rest of the New England system where the situation is more balanced or even approaching deficit conditions. On that basis, Maine is very well positioned in terms of electricity generation, especially if we take into account that its strengthening DR program is further reducing peak load growth.[63]

Although Maine's plant fleet is relatively new compared to the resources in the rest of the New England system, the average capacity factor of selected (newer) CCGT plants is distinctly lower because of lack of access to the high growth load pockets of Boston and Southwest Connecticut. As mentioned above, Maine Independence Station is an example of such a plant (see Figure 14 for more details). In addition, the operating profile of some units in Maine is trending down due to increased local congestion within Maine.

Strengthening environmental measures will pose a challenge to the region and to the affected generators, and may increase retail electricity rates. However, we expect that Maine would suffer a more muted impact from RGGI on overall LMPs given the likelihood that relatively cleaner and more efficient resources would tend to set prices during periods of congestion in Maine versus the rest of New England.

[63] Note however that this surplus is mitigated by the fact that Maine heavily relies on natural gas for its generation (44% of installed capacity is gas-fired, as discussed in Section 2.2.1). Therefore, Maine's supply surplus is vulnerable to fuel supply disruptions.

3 Summary of investment needs from ISO and utility studies

In this section, we will review the analysis of relevant studies that have been conducted by the ISO-NE, NMISA, and the IOUs' reliability reports submitted to the MPUC. The intent of the resource plan is to synthesize publicly available studies and documents, rather than to supplement these materials with an independent analysis. As will be discussed later in this Report in more detail, all of the studies are confident that Maine has adequate capacity to meet demand presently and in the medium-term. However, these studies all raise the issue of transmission reliability and focus extensively on the importance of transmission investment to address this concern. It is important to note that all forward-looking transmission projects proposed in these studies have not yet been reviewed formally by the MPUC, nor have alternatives to these projects been considered. Nothing in this report, including this section, should be read as confirmation of a utility's position on reliability, investment necessity, or economic benefit. The assertions of reliability improvement and economics benefit described in these investment assessments need to still be validated by the Commission. Notwithstanding this issue, we have summarized below the views of the utilities and ISO-NE with respect to transmission investment needs, since transmission investment strategy will directly affect generation investment and the overall strategy for the state of Maine in pursuing least cost energy for its constituents.

3.1 Regional analysis conducted by or with the coordination of ISO-NE

3.1.1 2007 Regional System Plan

The Regional System Plan ("RSP") is an annual report that provides an assessment of the supply-demand resources for resource adequacy and the transmission system needs of the New England region for reliability. The 2007 RSP, which covers the period 2007 to 2016, encompasses the entire ISO-NE control area and is prepared by the ISO-NE in coordination with transmission and distribution utilities and other market participants. The RSP is a requirement of the ISO-NE per their FERC-approved Open Access Transmission Tariff ("OATT"). The conclusions in the RSP are used by the ISO-NE to coordinate transmission investment, develop new policies and market products, and refine existing market products to ensure adequate pace of investment.

We summarize below the conclusions reached by ISO-NE in its 2007 RSP with respect to generation and transmission investment needs, with special focus on Maine.

Generation

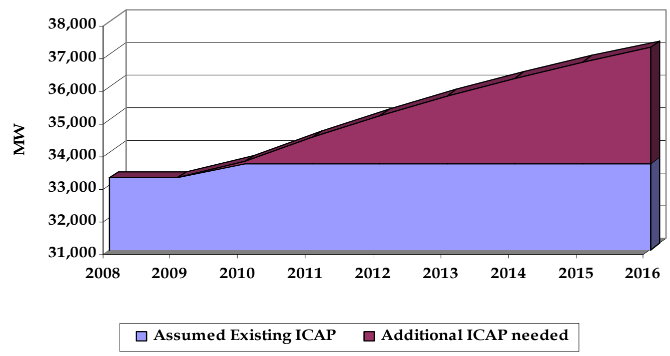
According to the 2007 RSP, New England has adequate installed capacity to meet its regional capacity needs through 2009. While additional resources are needed starting 2010 (Figure 23), the ISO-NE is optimistic that it can meet the projected capacity needs and the resource adequacy requirements for 2010 and beyond through the FCM.[64] The study revealed that

[64] As will be discussed in detail in Section 1, the FCM will procure the required amount of installed capacity resources through an auction three years in advance of the year that the resources are needed.

assuming that there are no additions or retirements, an additional 60 MW of capacity would be required in the region by 2010 and an additional 3,543 MW of capacity will be needed by 2016 to meet the resource adequacy criterion of disconnecting non-interruptible customers no more than one day in 10 years for New England as a whole.[65] This is referred to as the Loss of Load Expectation ("LOLE") of 1 day in 10 years. Operationally, if the identified capacity is not developed, New England's risk of suffering a regional system outage increases.

It is notable that RSP 2007 concluded that adding resources above 700 MW in the Maine sub-areas would not contribute significantly to alleviate the potential increase in system-wide LOLE in the long run, because resource needs are more crucial in the sub-areas of the Greater Connecticut area (Norwalk, Southwest Connecticut, and Connecticut) for purposes of system stability.[66] Moreover, various transmission limits would reduce the load-serving capability of the resources located in Maine to meet system-wide needs.[67]

Figure 23. Representative capacity requirements for New England, 2008-2016



Year	Future ICAP requirement	Assumed Existing ICAP	Additional ICAP Needed
2008	31,848	33,199	
2009	32,657	33,199	
2010	33,705	33,644	61
2011	34,449	33,644	805
2012	35,103	33,644	1,459
2013	35,716	33,644	2,072
2014	36,250	33,644	2,606
2015	36,755	33,644	3,111
2016	37,187	33,644	3,543

Source: ISO-NE, 2007 RSP, page 33

The 2007 RSP, however, identified Western Maine as one of the three areas that need additional generation to ensure local reliability.[68] Western Maine has generation that has been designated as daily second-contingency generation.[69] Infrastructure reinforcements for this area are also being evaluated as part of the Maine Power Reliability Program, which we discuss further below in Section 3.1.2.

[65] ISO-New England Inc. "2007 Regional System Plan (RSP)," October 18, 2007, page 33.

[66] ISO-NE, RSP 2007, page 41.

[67] ISO-NE, RSP 2007, page 39.

[68] ISO-NE, RSP 2007, page 91.

[69] ISO-NE, RSP 2007, page 92.

As of May 2007, there were a total of 90 projects, totaling approximately 10,500 MW, in the ISO's Generation Interconnection Queue. On this system-wide list, Maine has a total capacity of 348 MW actively seeking interconnection and 390 MW commercial generation-interconnection requests.[70] The active generation-interconnection requests are those that are actively under study or developing interconnection while the commercial generation-interconnection requests are those that have a commercial operation date.[71] As we discussed in Section 2.5.1, these new entrants are primarily wind generators. Due to the nature of wind generation, the new plants will be producing substantially less energy than their installed or nameplate capacity rating. As a result of their energy constrained operating profile, they will also not be contributing substantially towards the system-wide resource adequacy (LOLE) requirement (indeed, they will only qualify for part of their nameplate capacity in the FCM). However, their operating profile will also mean that they are unlikely to be running into the 700 MW limit that ISO-NE has defined for Maine's contribution to the system-wide LOLE requirement, described above.

Transmission

Maine currently has two 345 kV transmission paths from southern to central Maine and two 345 kV paths from northern Maine to New Brunswick (given the start of commercial operations of the Northeast Reliability Interconnection). In the central part of the system, Maine has a single 345 kV path, which has limited reliability performance and is a weak link in the system. Maine, together with New Hampshire and Vermont, belongs to the northern New England transmission system, which is characterized as having long and old 115 kV lines with limited capacity and flexibility to accommodate maintenance outages.[72] In addition, the RSP described the 115 kV lines in this area as having "*limited dynamic reactive-power resources and high real-and reactive power losses.*"[73] The RSP highlights concerns about the transmission system's ability to efficiently and effectively serve load and to integrate generation.[74]

As identified in the RSP 2007, the northern New England transmission system has two main issues: (1) the maintenance of the general performance of the long 345 kV corridor, and (2) the reliability of supply to meet demand. In addition, ISO-NE has concerns about the system's thermal and voltage performance, stability, and reliance on several special protection systems that require undesirable operation (of generation) to maintain grid reliability. Figure 24 below illustrates the key elements of the Maine transmission system, while Figure 25 shows how Maine interconnects with Northern New England.

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70 ISO-NE, RSP2007, page 40.

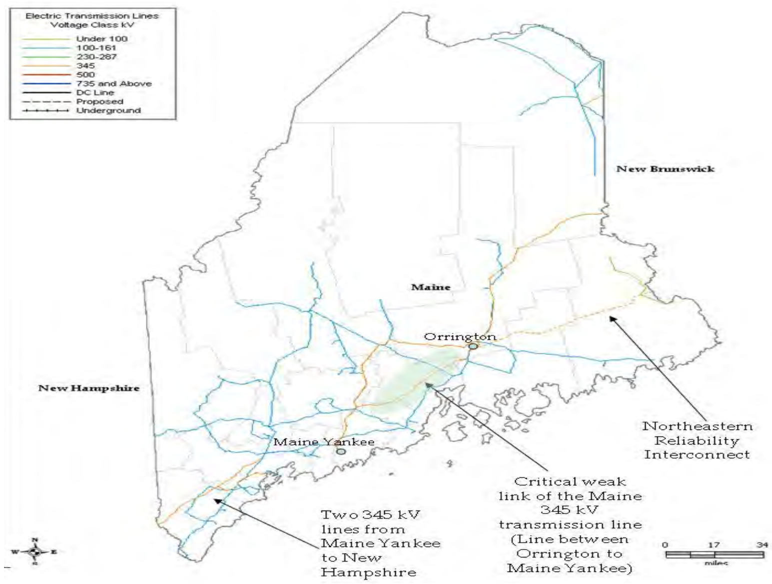
71 According to an email correspondence with Mr. Kurt Dahdah, ISO-NE Market Support Specialist, on Nov. 16, 2007

72 ISO-NE, RSP 2007, page 75.

73 ISO-NE, RSP 2007, page 77.

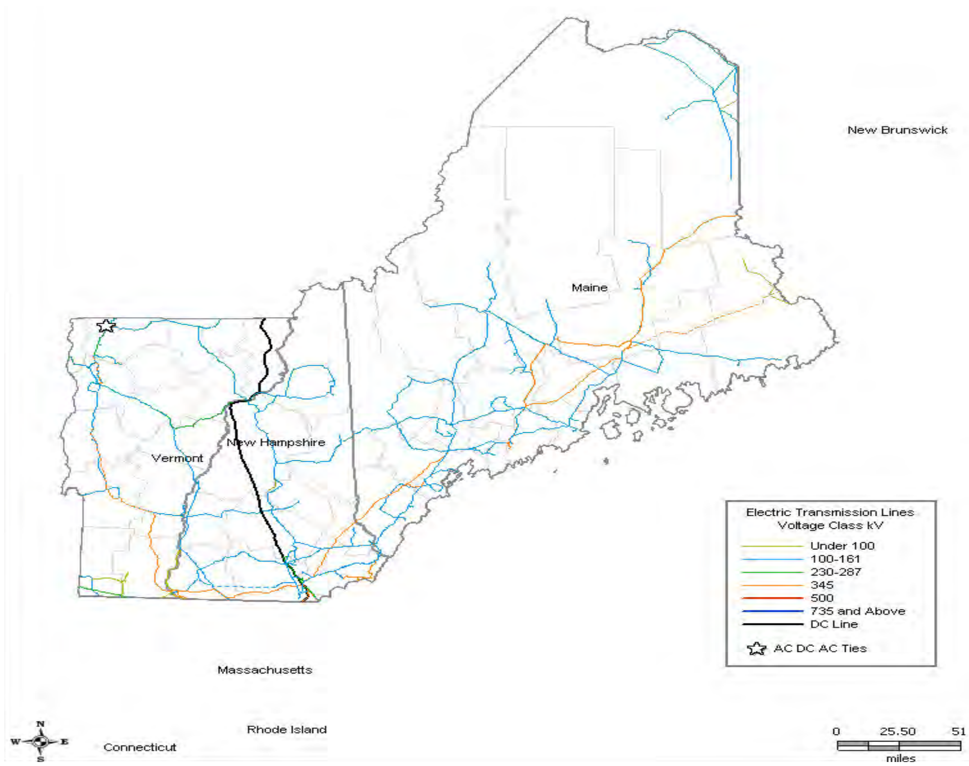
74 Ibid.

Figure 24. Maine 345kV transmission lines



Source: Map created with Energy Velocity Suite (Accessed October 26, 2007)

Figure 25. Map of northern New England



Source: Map created with Energy Velocity Suite (Accessed October 26, 2007)

As identified in the RSP 2007, the northern New England transmission system has two main issues: (1) the maintenance of the general performance of the long 345 kV corridor, and (2) the reliability of supply to meet demand.[75] In addition, ISO-NE has concerns about the system's thermal and voltage performance, stability, and reliance on several special protection systems that require undesirable operation (of generation) to maintain grid reliability.[76] Furthermore, ISO-NE believes that inadequate voltage performance is possible due to the underlying systems of 34.5 kV, 46 kV, and 69 kV lines in Maine, which are exceeding their capabilities and must be upgraded.[77] The system stability concerns stem from the observation that load has grown and a significant amount of generation was added over the past several years in Maine and New Hampshire, and specifically in areas that have limited transfer capability and transmission expansion opportunities.

The RSP enumerated several transmission studies and projects that are underway to address some of these issues. In response to the area's thermal and voltage issues, CMP is proposing 115 kV expansions in western Maine.[78] In addition, the ISO-NE is conducting studies to assess the alternatives for either maintaining or improving system reliability in Maine. These analyses, according to the 2007 RSP, will impact Maine's Orrington-South interface, Suroweic-South interface, and Maine-New Hampshire interface.[79] To reduce the potential voltage concerns, upgrades on the north of Augusta and around Rumford as well as installation of a new 115 kV substation are being assessed. Other projects mentioned in the RSP that are being explored include reinforcements on the 115 kV system, system reinforcements south of Orrington, and a new substation at Maguire Road in southern Maine.[80]

Among the five major ongoing transmission projects in New England cited in the 2007 RSP (see Figure 26 below), one is in Maine. In fact, the Northeast Reliability Interconnection ("NRI") Project which connects the Point Lepreau substation in New Brunswick, Canada to the Orrington substation in northern Maine, is now commercially operational. The NRI as illustrated in Figure 27 below. The 2007 RSP states that this project will increase transfer capability from New Brunswick to New England by 300 MW (although the thermal capability of the new transmission line is far greater).[81] The recently completed NRI Project is owned by the Bangor Hydro-Electric Company.[82]

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[75] Ibid.

[76] ISO-NE, RSP 2007, page 75.

[77] Ibid.

[78] ISO-NE, RSP 2007, page 78.

[79] ISO-NE, RSP 2007, page 79.

[80] Ibid.

[81] ISO-NE, RSP 2007, page 8.

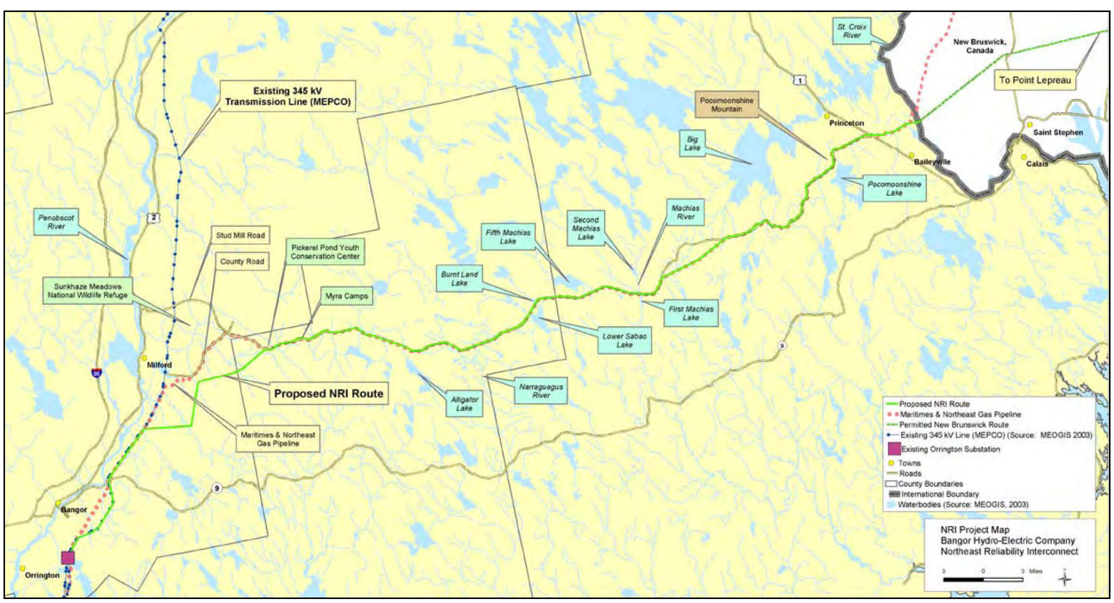
[82] October 2007 ISO-New England Project Listing Update Draft, September 12, 2007

Figure 26. Major transmission projects in New England

Name	Description	Status
Northeast Reliability Interconnection Project	- 144-mile, 345 kV transmission line and supporting equipment that connects Point Lepreau substation in New Brunswick, Canada to the Orrington substation in northern Maine	Completed as of December 2007
Northwest Vermont Reliability Project	- 36-mile, 345 kV line linking the West Rutland substation to a new 345 kV substation in New Haven Vermont; New 28-mile 115 kV line; - Various 115 kV components	Line from West Rutland to New Haven was completed in early 2007; Other components are scheduled to be completed in 2008
Boston 345 kV Transmission Reliability Project (NSTAR 345 kV Transmission Reliability Project)	-Two 17-mile cable to K Street substation; One 11-mile cable to Hyde Park susbtation	First portion was completed in 2007 and the final cable is scheduled to be completed in 2008
Southwest Connecticut Reliability Project	- Phase 1: 20-mile 345 kV circuit from Bethel to Norwalk; - Phase 2: 70-mile 345 kV circuit from Middletown to Norwalk; 115 kV lines from Norwalk to Glenbrook	Phase 1 was put in service in 2006; Phase 2 is planned to be put in service in 2009; Norwalk to Glenbrook line to be put in service in 2008
Monadnock Project	- New 345/115 kV substation at Fitzwilliam, New Hampshire; - Several 115 kV upgrades	Planned in-service date is 2009

Source: ISO-NE, RSP 2007

Figure 27. Northeast Reliability Interconnection Project



Source: Bangor Hydro Electric Company website

In addition to these transmission projects, the ISO-NE identified alternatives to address the above-mentioned transmission system performance issues in Maine. The following, which are excerpted from the 2007 RSP, are the alternatives identified by the 2007 RSP:[83]

- *Closing the Y-138 line:* While this project is being developed to address the central New Hampshire reliability needs, it will also provide some improvements, albeit limited, to the Suroweic-South and Maine-New Hampshire voltage and thermal performance problems. Closing the Y-138 line, which as an open line that currently does not allow electricity to flow between White Lake and Saco Valley, would allow for increased power transfers from Maine and New Brunswick into the region.[84]

- *New Hampshire Seacoast Reliability Project:*[85] Two components of this project involve Maine. First, looping section 391 of the Buxton-Scobie 345 kV line into the Deerfield 345 kV substation is said to reduce the complexities and interdependencies of the generator output and voltage limits of the Surowiec-South and Maine-New Hampshire interfaces as well as enhance the thermal-transfer capability of these interfaces.[86] Second, upgrading 115 kV facilities near the southern Maine-New Hampshire border will not only support load growth in the New Hampshire coastal area and southern Maine but will also address the potential thermal overloads and voltage issues near the Maine-New Hampshire border during peak-load or shoulder peak-load periods.[87]

- *Maguire Road Switching Station 115 kV Project:*[88] The two components of this Project, namely (1) eliminating critical Buxton 345 kV contingencies resulting from the failure of key circuit breakers, and (2) mitigating violations of voltage and thermal reliability criteria within CMP's southern Maine transmission system, address the stability limitations of the Surowiec-South Maine-New Hampshire interfaces and the voltage reliability issues in southern Maine.[89]

- *Rumford-Woodstock-Kimball Road (RWK) Corridor Transmission Project:*[90] The RWK project, which includes the construction of a new transmission line, upgrading of existing

[83] Excerpted from pages 78-80 of the ISO-NE, RSP 2007.

[84] New Hampshire Profile. Available online at http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/nh_profile.pdf

[85] As of October 2007, the status of this project is still under the "proposed" category of the ISO-NE Project Listing Update.

[86] ISO-NE, RSP 2007, page 78.

[87] Ibid.

[88] As of October 2007, this project is still in the planning stage. This is owned by the Central Maine Power (CMP) Company.

[89] ISO-NE, RSP 2007, page 78.

[90] Owned by the CMP, this project is not yet approved by the ISO-NE.

transmission lines, installing additional capacity banks, and changing substation configurations, will increase the system reliability of the western Maine network.

- *Maine Power Reliability Program (MPRP):* This study identified several inadequacies in the Maine transmission system: insufficient 345 kV transmission, insufficient 345/115 kV transformation capacity, insufficient 345 kV transmission support for Portland and southern Maine, insufficient transmission infrastructure in western, central, and southern Maine regions, and insufficient transmission infrastructure in Mid-coast and Downeast Maine regions. Section 3.1.2 will discuss in detail the findings of this study.

- *Maine Power Connection*: CMP and Maine Public Service ("MPS") have agreed to study the feasibility of a new interconnection between the MPS system and the Maine Electric Power Company (MEPCO) system that would provide a direct electrical connection to the New England transmission system (Figure 37 on page 58).

- *Adding capacitor banks in western Maine and at Maxcys:* This could improve the Maine-New Hampshire voltage limits and support local voltage requirements.

- *Redesigning the SPSs at Maxcys and Bucksport:* The replacement of the Maxcys SPS and Bucksport over current SPSs with the MEPCO SPS, which has a planned in-service date at the end of 2007, will eliminate the poor transient-voltage response in the local area, possible inadvertent SPS operation, difficulty in ensuring the poor operation of the normal line-protection equipment, and a discontinuity in the protection provided by the existing system.

- *Adding a 500-600 MVAR dynamic-reactive device to provide voltage control at the Deerfield 345 kV substation:* This project would ease the difficulties and interdependencies of the generator output and voltage limits of the Maine-New Hampshire interface and could improve the Maine-New Hampshire and northern New England Scobie and 394 interface stability limitations.

3.1.2 Maine Power Reliability Program Needs Assessment[91]

The Maine Power Reliability Program ("MPRP"), initiated and led by Central Maine Power, began in early 2007 to assess the Maine bulk power transmission system and Pool Transmission Facilities ("PTFs")[92] as well as to identify and evaluate alternative transmission solutions to

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[91] This report focuses on the MPRP Needs Assessment report. The results of the Non-Alternatives Study were not available in fourth quarter 2007, when this report was written. The preliminary results of the Non-Alternative Study was released today (April 7, 2008) and is available online at http://www.mainepower.com/NTA_Forum_040708.pdf

[92] As defined in the Open Access Transmission Tariff (OATT), Section II.49, the PTFs are "*the transmission facilities owned by participating transmission owners over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the transmission operating agreement, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System.*"

maintain or improve current and future system reliability.[93] We reviewed the June 2007 *Needs Assessment of the Maine Transmission System* ("Needs Assessment"), which concludes the first step in the three-step process of the MPRP Study.[94]

The Needs Assessment, which was performed under stressed system conditions, took into consideration the following assumptions: (1) a 2017 summer peak level, (2) upgrades on generation and transmission system[95] in both Maine and New England, and (3) no retirements of generating stations in Maine. In addition, the Study, which used eighteen different operating scenarios, was conducted without the Special Protection Systems (SPS) in Maine and New Brunswick.[96,97]

The Needs Assessment Study concluded that Maine's transmission system is aging and approaching its technical and physical limits to serve Maine's growing electrical demand needs.[98] It concluded that there are six main reliability concerns in Maine's transmission system.

First, the Needs Assessment concluded that the 345-kV transmission system, which is the backbone of the bulk power system in Maine and throughout the New England system, is inadequate.[99]

As identified in the RSP 2007, the northern New England transmission system has two main issues: (1) the maintenance of the general performance of the long 345 kV corridor, and (2) the reliability of supply to meet demand. In addition, ISO-NE has concerns about the system's thermal and voltage performance, stability, and reliance on several special protection systems

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[93] RLC Engineering, "Final Report Maine Reliability Program (MPRP) Needs Assessment of the Maine Transmission System," June 19, 2007, p. ii. Both a public and non-public version of this report is available. In order to ensure confidentiality of Critical energy Infrastructure Information (CEII), we are summarizing and quoting from the public report only.

[94] According to the MPRP Study Scope presentation dated 13 March 2007, the MPRP will be conducted in three steps: (1) A "Needs Assessment" to identify the requirements for reliability, operability, and maintainability, (2) An "Alternatives Assessment" to develop and assess the different transmission solutions to meet the needs identified in the first step, and (3) A "Final Reliability Analysis" to ensure that the proposed program is cost-effective and achieves all the applicable reliability standards.

[95] For information about the actual transmission projects included in the base case assumptions, please refer to pg. 22 in the non-public version of the MPRP Report.

[96] MPRP, page ii.

[97] A Special Protection System is defined in the non-public version of the MPRP Report (page 19) as "a protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows."

[98] MPRP, page ii.

[99] MPRP, page iii.

that require undesirable operation (of generation) to maintain grid reliability. Figure 24 below illustrates the key elements of the Maine transmission system, while Figure 25 shows how Maine interconnects with Northern New England.

As shown in Figure 24, while Maine has two 345-kV paths from Southern to Central Maine and has recently added another 345 kV line from Northern Maine to New Brunswick (with the NRI Project), it has a single 345-kV path in the central part of its system between Central and Northern Maine, which is said to be a critical link to the reliability of Maine's bulk power transmission. The Study highlighted that an outage on this critical link or a double circuit tower contingency on the 345 kV corridor may trigger a blackout.

Second, the Needs Assessment disclosed that there is insufficient transformation capacity as exemplified by the thermal overloads of the Maine 345/115 kV autotransformers under "all-lines-in" conditions.[100] The study highlighted the importance of the autotransformers shown in Figure 28 (including Orrington and four other major 345/115 kV substations along the eastern shore of Maine, as seen in the figure below) in the reliability of the Maine transmission system.

Third, the MPRP Needs Assessment showed that there is insufficient 345 kV transmission support for Portland and the Southern regions.[101] As discussed in the Needs Assessment, any outage in the South Gorham substation, which is served by a radial 345 kV transmission line from Buxton substation to the Wyman Station, cuts off the service of the South Gorham station and its supply to the Portland and Southern regions, possibly causing blackouts.[102] The Needs Assessment proposed transmission upgrades and system reinforcements which would provide additional 345/115 kV transformation capacity necessary to meet transmission reliability criteria.

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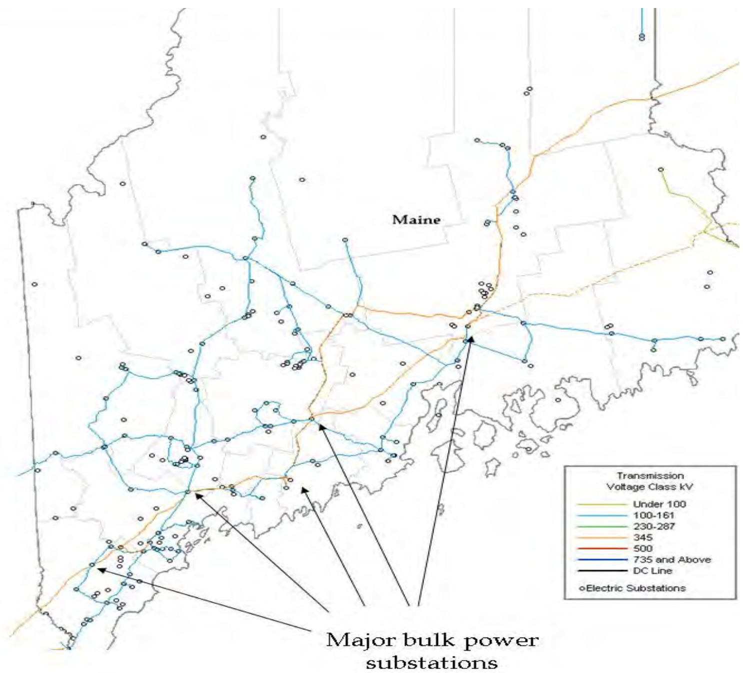
[100] MPRP, page iii.

[101] MPRP, page iii.

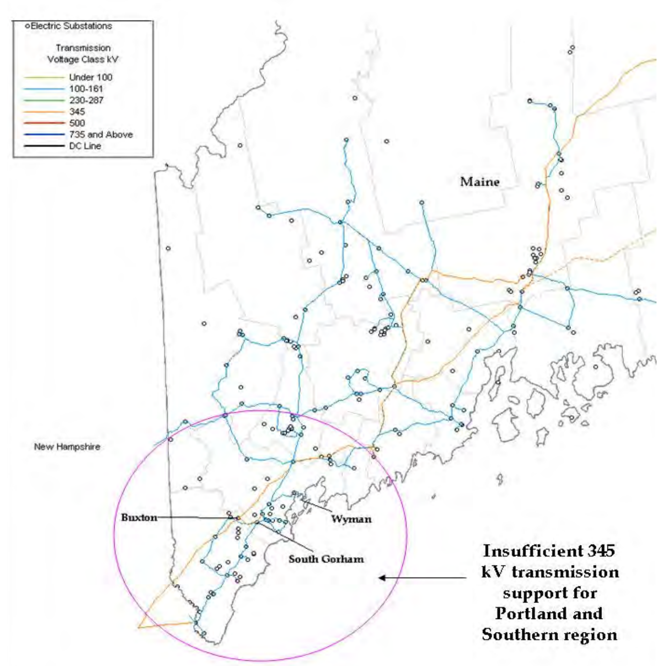
[102] MPRP, page iii.

Figure 28. Insufficient transmission support at major bulk power substations identified in the MPRP



Map created with Energy Velocity Suite (Accessed April 7, 2008)

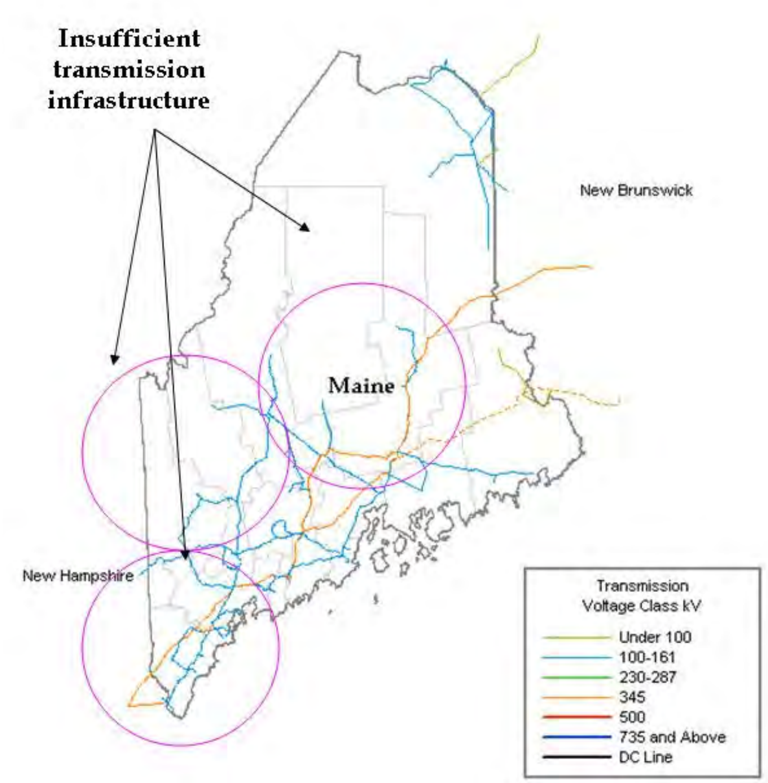
Figure 29. Portland and Southern regions of Maine



Map created with Energy Velocity Suite (Accessed October 26, 2007)

Fourth, the Needs Assessment revealed that the Western, Central, and Southern Maine regions (Figure 30) do not have sufficient transmission infrastructure.[103] Under different modeled scenarios in the Needs Assessment, thermal overloads or voltage violations occur in these regions. In order to solve these problems, the MPRP Needs Assessment recognized the need for transmission upgrades in Southern Maine, including the installation of system reinforcements to provide additional 345/115kV transformation capacity.

Figure 30. Western, central, and southern Maine regions



Map created with Energy Velocity Suite (Accessed October 26, 2007)

Fifth, the Needs Assessment concluded that there is insufficient transmission infrastructure in the Mid-Coast and Downeast Maine regions (see Figure 31). Unlike in the Western, Central and Southern Maine regions, these two areas do not have generation to rely on for ensuring adequate local supply.[104] The Needs Assessment modeling showed that low voltage violations and thermal overloads occurred.[105]

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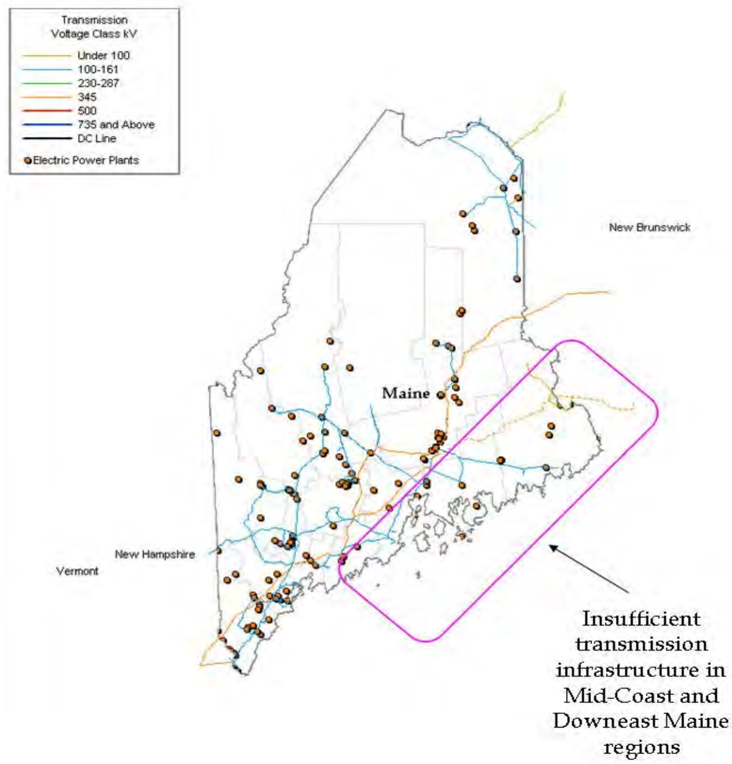
[103] MPRP, page iii.

[104] MPRP, page iii.

[105] MPRP, page iii.

Figure 31. Mid-coast and Downeast regions of Maine



Map created with Energy Velocity Suite (Accessed October 26, 2007)

Finally, the Needs Assessment concluded that there are insufficient thermal capacity ratings of key transmission lines.[106] In addition, four additional lines were overloaded under post-contingency conditions.

3.1.3 New England Independent Transmission Company "Green Line" filing to FERC

In analyzing stakeholder analyses about infrastructure needs in Maine, we also reviewed the potential for economic transmission projects in New England, and proposed implications for Maine. For example, the New England Independent Transmission Co LLC ("New England ITC") is proposing to build a 660 MW high voltage direct current underwater transmission line that stretches approximately 140 miles from Maine to the greater Boston area. The cable, which is called the Green Line, would run from the site of the deactivated Maine Yankee nuclear

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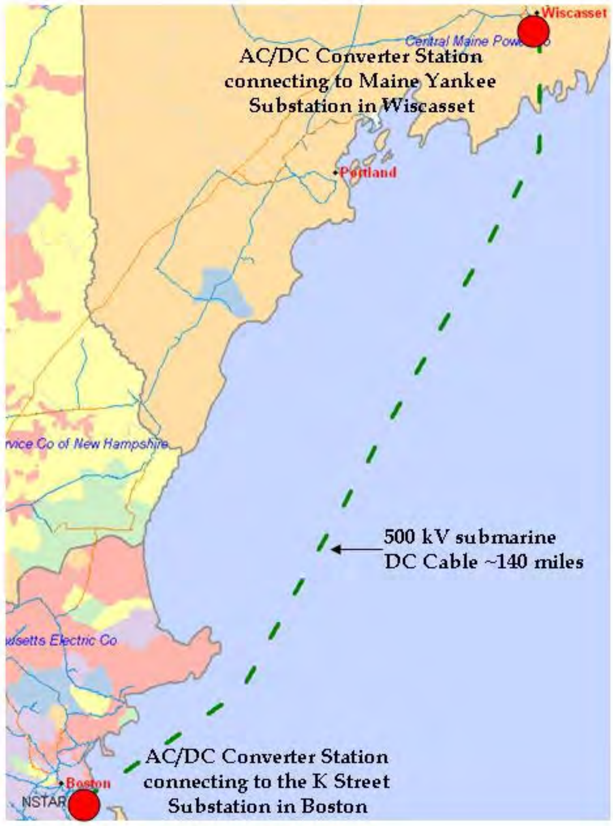
[106] During the modeling tests, five 115 kV lines were overloaded in both the base case conditions and post-contingency conditions. The five transmission lines are identified in the non-public MPRP, page 92.

power plant in Wiscasset, Maine to an undetermined location in South Boston's waterfront industrial zone near a major electric switching station on K Street (Figure 32).[107]

Figure 32. Green Line Map



Source: New England Transmission ITC[108]

The cable would enable the delivery of substantial quantities of (presumably, lower cost) energy from Maine to the load pocket of Boston. Indeed, the sponsor named the project "Green Line" because it was anticipated that the DC link would be used to export green power generated by Maine's wind turbines, hydroelectric generators, and other renewable Maine power plants (such as the biomass plants that use wood waste from paper and lumber mills). The cable, which would take about two years to build, is not expected to be in service before 2013. Indeed, the project is still in development phase. In February 2007, the FERC had granted the New England ITC's petition for declaratory order that it meets the independence and capability

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[107] Petition for Declaratory Filing submitted by the New England Independent Transmission Company to FERC dated December 4, 2006. Available online at http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2006/dec192006/a6_neitc.pdf

[108] Ibid, page 2.

requirements of the ISO-NE open access transmission tariff.[109] Since May 2007, the New England ITC has been engaged in negotiations with ISO-NE to develop an ITC Agreement.[110]

Such a project would allow for more generation exports from Maine to rest of New England. This would generally benefit ratepayers in rest of New England. The impact on Maine's LMPs are difficult to project without detailed economic analysis, but generally there is an expectation that LMPs in Maine would rise as a result of the increased exports to higher priced sub-region of Boston due to higher opportunity costs for Maine generators, and the effect of the lifting export constraint. That increase may be moderated but not completely offset by the indirect effect of lower cost resources lowering the overall New England system-wide price. In addition, depending on the actual configuration of the interconnection, there may be an opportunity to reinforce some portion of the 345 kV AC system within Maine as part of this project, although it is primarily a DC link.

Furthermore, on a conference in Washington, D.C. in October 2007, the ISO-NE executives had disclosed that they have been approached by a number of stakeholders with similar propositions for DC-based, economically-oriented transmission investments. In December, ISO-NE staff asked potential project sponsors to discuss their projects at a forum of market participants, namely the scheduled Planning Advisory Committee (PAC) meeting. The Northeast Energy Link proposed by Emera was presented at the December 18, 2007 PAC meeting. As outlined by Emera (and BHE representatives), this project is being developed in response to recent ISO-NE Scenario Analysis study that recognized the necessity and benefits of importing additional clean power and renewable energy from Northern Maine and Canada to meet RPS and RGGI requirements and improve the diversity of resources available to the region. Northeast Energy Link is a multi-stage inter-regional project. Stage one of this project will consist of two 660 MW HVDC lines from Orrington, Maine to NEMA/Boston.[111,112]

In addition to the Maine Power Reliability Program (MPRP) and the Maine Power Connection (MPC), Central Maine Power also described its early conceptual stage project, the Maine-Canada Renewable Highway during the ISO-NE PAC meeting on December 18, 2007. Northeast Utilities (NU) also proposed a HVDC line from Hydro-Québec to central New Hampshire. This transmission project, as described by NU, would likely utilize the 345 kV upgrades (as described in RSP 2007) in New Hampshire and Vermont to meet future reliability needs. The HVDC line will further link Newington, New Hampshire to Boston. NU believes that its project optimizes use of existing and planned bulk power grid – connecting the DC tie line from Hydro-Québec at a suitable location on the New England AC system and providing a

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[109] Order Granting Declaratory Order, Issued February 20, 2007, FERC Docket No. EL07-21-000

[110] New England ITC, "New England ITC and the Green Line: A PowerPoint Presentation to the NEPOOL Transmission Committee," June 2007, page 3.

[111] Source: ISO-NE, PAC 26, December 18, 2007.

[112] London Economics International LLC was commissioned by Emera for the economic study of the Northeast Energy Link.

new, strong yet separate reliability path from Hydro-Québec. And the addition of North-South DC connection allows for enhanced power flows to southern New England load centers.

At this same PAC meeting, FPL Energy also proposed to develop a cable from Seabrook to Boston/Canal area which will solve reliability issues in SEMA. Again, this project is also at the early planning stage as there are at least three route options being considered. Interconnection points under review are Seabrook, Canal, K Street, and Kingston.

Note that not all of the proposed transmission projects will be built and some of them are mutually exclusive. A fair amount of interest in the proposed projects, however, suggests the further investigation is necessary regarding the value of bringing renewable and cheaper resources from Northern Maine and Canada down to load pockets in Southern New England.

3.1.4 ISO-NE 2006 Annual Report

The 2006 ISO-NE Annual Report issued in May 15, 2007 presents essentially the same analysis and conclusions as that of the 2007 RSP discussed in Section 3.1.1, although it does not provide as detailed analysis of Maine-specific issues. Moreover, the ISO-NE stated in the Annual Report that it is confident that sufficient new generation will be in place to address the fundamental challenge of rising demand and flat supply. The FCM is expected to provide the incentives for attracting needed resources to meet demand.

3.1.5 ISO-NE 2006 State of the Market Report

The 2006 ISO-NE State of the Market Report ("SOM") identified Maine as an export constrained location. The 2006 SOM said that exports from Maine to the South are frequently limited by transmission constraints. According to the SOM, the implementation of Standard Market Design in 2003 helps in managing such transmission constraints in an efficient manner (through locational marginal prices), but do not ameliorate the problem. Because of the constraints on exports from Maine, price spikes in Maine were more predictable. Furthermore, Maine faced a lower LMP than rest of New England. For instance, the average real time price of $58.62/MWh in Maine was 7% lower than the average New England hub price at $62.67/MWh in 2006, according to the SOM. We will discuss in more detail LMP trends in Section 5 of this Report.

3.2 Northern Maine Independent System Administrator

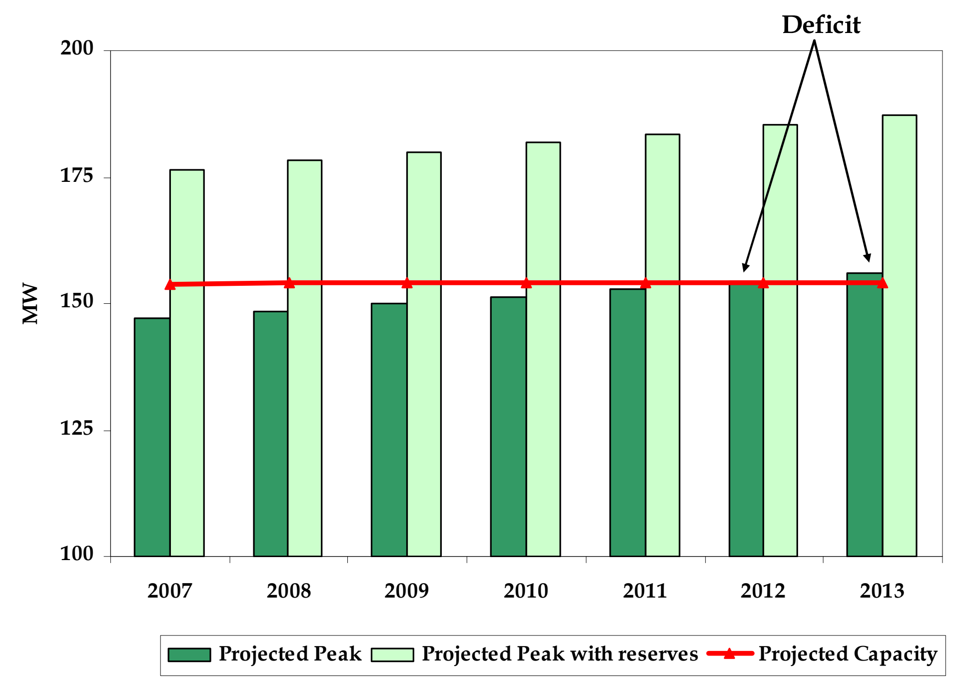
On March 30, 2007, NMISA issued the results of the seven-year *Outlook on the Assessment of the Adequacy of Generation and Transmission Facilities on the Northern Maine Transmission System* ("NMTS Outlook"). The NMISA Outlook covers the load forecast for NMPTS, catalogues the available generation resources, considers resource adequacy, and describes transmission planning initiatives.

Generation

The NMISA Outlook stated that the NMISA system, in the base case scenario, will have a capacity deficit in all the forecasted years (2007-2013), when considered on a stand-alone basis. It should be noted that in the base case scenario analysis, the computation included a 20% planning reserve margin target over projected load and did not include the Boralex Sherman facility and projects that are in the early stage of development in its projected capacity. Therefore, the conclusions regarding resource inadequacy are based on highly conservative assumptions.

However, even if the 20% planning reserve target is removed from the projected load, Figure 33 shows that beginning in 2012, there may be a capacity deficit if new capacity is not brought online. Nevertheless, NMISA is optimistic that the deficiency can be satisfied either from off system purchases or from the construction or reactivation of generation resources not included in the Base Case.[113] It is however important to note that, from a reliability standpoint, the relevant area is the Maritimes Control Area, not NMISA.

Figure 33. NMISA projected load and capacity under seven-year Outlook



Source: NMISA Seven Year Outlook

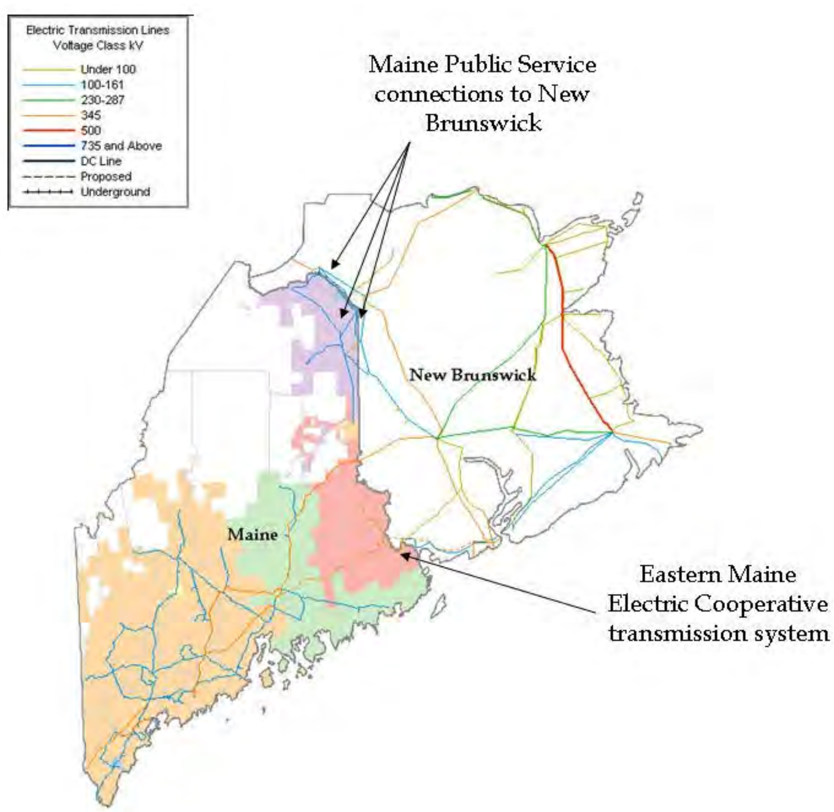
Transmission System

The NMTS consists of two independent transmission systems that are interconnected through the New Brunswick ("NB") transmission system -- the Maine Public Service ("MPS") System and the Eastern Maine Electric Cooperative ("EMEC"). As shown in Figure 34, three transmission lines interconnect the MPS system to New Brunswick: (1) 100 MVA import rated interconnection from Flo's Inn to Beechwood, (2) a 64 MVA import rated interconnection at

[113] Northern Maine Independent System Administrator (NMISA), "Seven-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities on the Northern Maine Transmission System," March 30, 2007, page 10.

Tinker Station, and (3) 56 MWA import rated interconnection from Iroquois to Madawaska.[114] The EMEC transmission system is connected to New Brunswick via radial 69 kV transmission line from the Topsfield, Maine substation.[115]

Figure 34. Northern Maine transmission system



Map created using Energy Velocity Suite (Accessed October 26, 2007)

While no new major internal transmission projects are anticipated in the near future, the NMISA Outlook concludes that the NMTS will be able to meet the Northeast Power Coordinating Council ("NPCC") Reliability Standards during the seven-year period. Specifically, it revealed that there is no existing or emerging shortage of transmission capacity or transmission constraints over the next one to five years or within six to seven years.[116,117] However, it recognized the importance of building additional transfer capability with

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[114] NMISA, page 7.

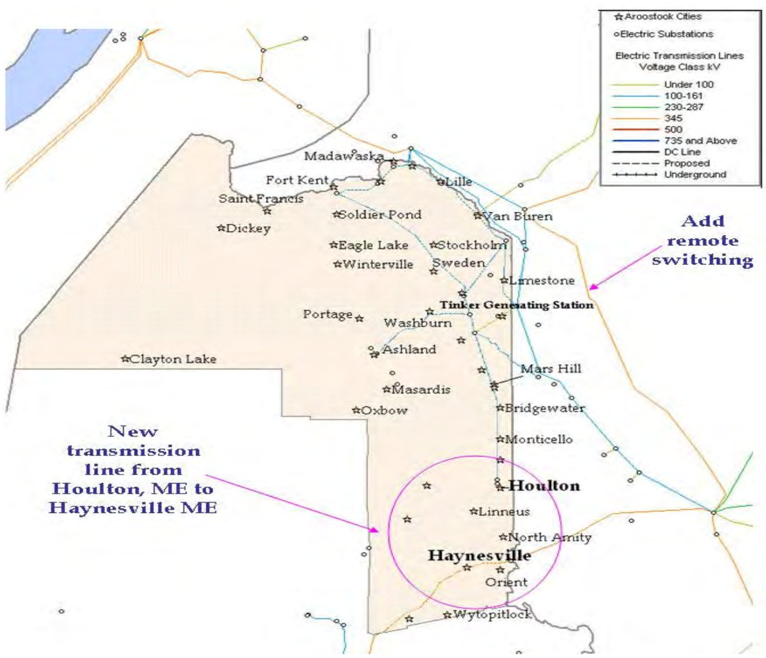
[115] Ibid.

[116] NMISA, page 8.

[117] The NMISA defines transmission constraint as something that will likely occur within 1-5 years while potential transmission constraint is something that likely will occur within 6-7 years.

neighboring systems to support new generating facilities in Northern Maine and to ensure reliability in case of an outage in the system.[118] The NMISA Outlook enumerated numerous non-NMTS systems interconnections that are being explored, as detailed in Figure 35 below. One of these proposed projects is the upgrade of the transformation equipment at Tinker Station, as an alternative to the construction of a fourth transmission interconnection between the NMTS and the NB Power system, which was not approved by the MPUC. This upgrade is said to increase transfer capability between the MPS and NB Power systems. Another plan that is currently being studied is the potential interconnection between the NMTS and the ISO-New England system through the construction of a new transmission line from Houlton, Maine to the MEPCO line at Haynesville, Maine.[119] This interconnection is currently being studied by ISO-NE jointly with MPS, MEPCO, and CMP (see Section 3.3.1 and Section 3.3.3 below for further details).

Figure 35. NMISA proposed plans



Map created using Energy Velocity Suite (Accessed October 26, 2007)

The NMISA Outlook also noted that the MPS has a series of capitalized maintenance projects in the pipeline. Although these projects will not increase the total transfer capability of the system, these will help avert outages and extend the useful lives of the facilities.[120] Moreover, NMISA recognized that the upgrades would have the potential to increase competition in the wholesale

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118 NMISA, page 8.

119 NMISA, page 8.

120 NMISA, page 8.

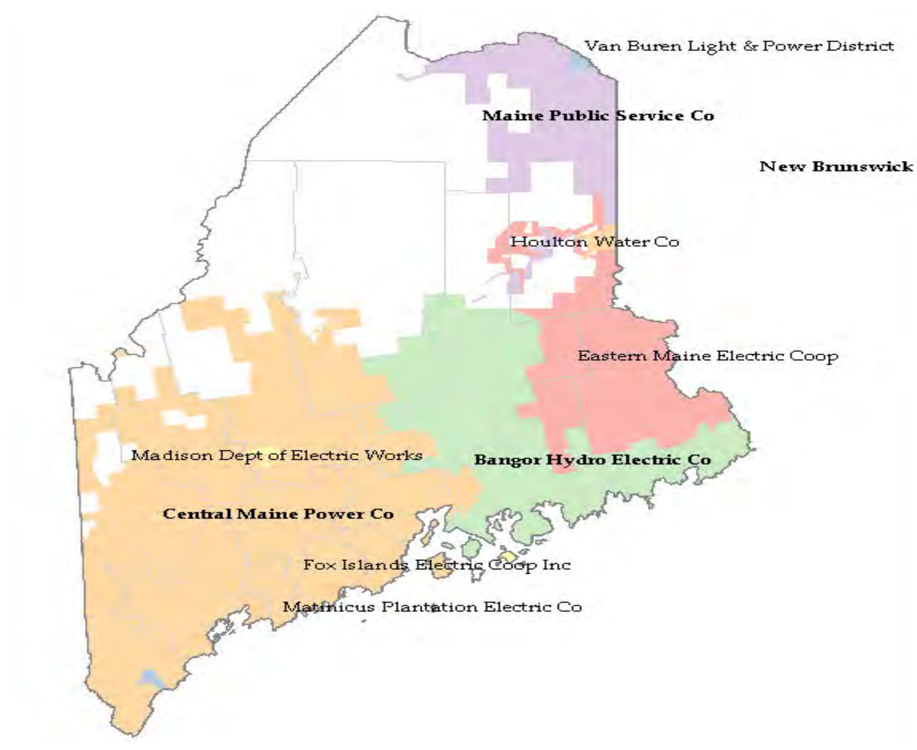
generation market, which could provide competitive pressures on prices, benefiting ratepayers in the longer term.

3.3 Reliability reports submitted by the Investor-Owned Utilities in Maine

The transmission and distribution utilities in Maine, namely CMP, BHE, and MPS, are required to submit a service territory *Bulk Level Transmission Grid Reliability and Adequacy Report* in accordance with the requirements of the Public Utilities Commission's long-term contracting and resource adequacy initiatives, in response to the Act. We reviewed these filings in the course of our analysis.

All the IOUs acknowledged that while their current transmission system is reliable and adequate to meet the normal load, they observed that transmission system upgrades and investments in new transmission lines would be able to address some of the transmission concerns such as capacity bottlenecks and thermal overloads. In addition, the IOUs remarked that upgrades and new transmission investments would be able to provide support to additional generation capacity. Although each IOU focused on its service territory (Figure 36 shows the service territories of these transmission and distribution utilities), the reports also referenced the various ISO-NE initiatives relevant to their service territory, as we discuss further below.

Figure 36. Service territories of the transmission and distribution utilities



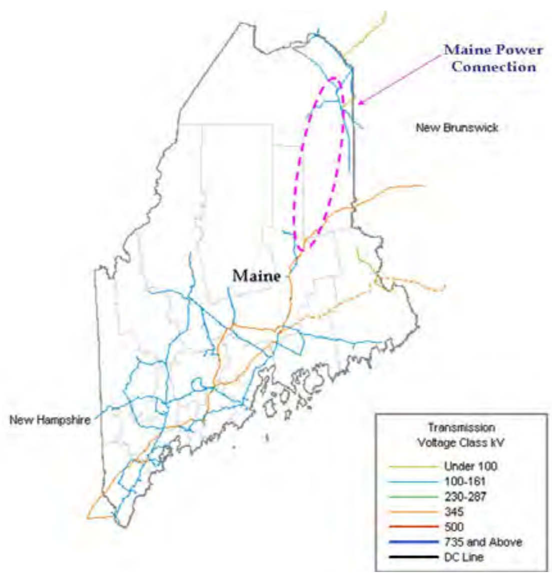
Map created using Energy Velocity Suite (Accessed October 26, 2007)

3.3.1 Central Maine Power

CMP, a subsidiary of Energy East Corporation and a pure transmission and distribution company, serves more than 596,000 customers in central and southern Maine.[121] CMP's transmission system comprises approximately 2,300 miles of transmission lines and 300 substations.[122] According to its submitted Reliability Report to the MPUC, CMP's current transmission system meets the established grid reliability criteria and objectives.[123,124] Since the Maine Power Reliability Program, which was discussed earlier in Section 3.1.2 as a project of the CMP, it highlighted in its reliability report filing to the MPUC the results of the Needs Assessment.

In addition to the Needs Assessment results, the CMP report also mentioned that together with the MPS and ISO-NE, it is currently studying the feasibility of building the Maine Power Connection (Figure 37), an interconnection between the MPS system and the Maine Electric Power System ("MEPCO") that will provide a direct electrical connection between northern Maine and the New England transmission system. Furthermore, the CMP is conducting a non-transmission alternative analysis to address reliability needs.

Figure 37. Maine Power Connection



Map created using Energy Velocity Suite (Accessed October 26, 2007)

121 Energy East Corporation Annual Report 2006, page 83.

122 Central Maine Power Company website.

123 Central Maine Power (CMP) Filing to the Maine Public Utilities Commission, September 14, 2007, page 5.

124 Since CMP is a participating transmission owner within the ISO-NE organizational structure, it must adhere to the reliability criteria and objectives defined by the ISO-NE and the Electricity Reliability Organization.

3.3.2 Bangor Hydro Electric Company

BHE is a pure transmission and distribution company, serving 110,000 customers in eastern Maine.[125] Based on its filed reliability report, BHE's bulk power system is currently adequate under normal load flow conditions (without contingencies).[126] However, BHE identified two issues that emerged during the analysis of its reliability:

BHE Bulk Power Transmission Assets:

1) Orrington 115 kV Bus
   - Betts Road Tap to Boggy Brook substation
   - Graham substation to Keene Road substation
   - Orrington substation to Bucksport Town line (65)
   - Orrington substation to Bucksport Town line (205)
   - Orrington substation to Graham station
   - Orrington substation to PERC
   - Orrington substation to Graham station (248)
   - Orrington substation to Graham station (249)
2) Graham 115 kV Bus
   - Graham substation to Rebel Hill Switching station
   - Rebel Hill switching station to Deblois substation
   - Deblois substation to Epping Tap
   - Epping Tap to Washington County substation
   - Rebel Hill switching station to Boggy Brook substation
   - Epping Tap to Harrington Substation

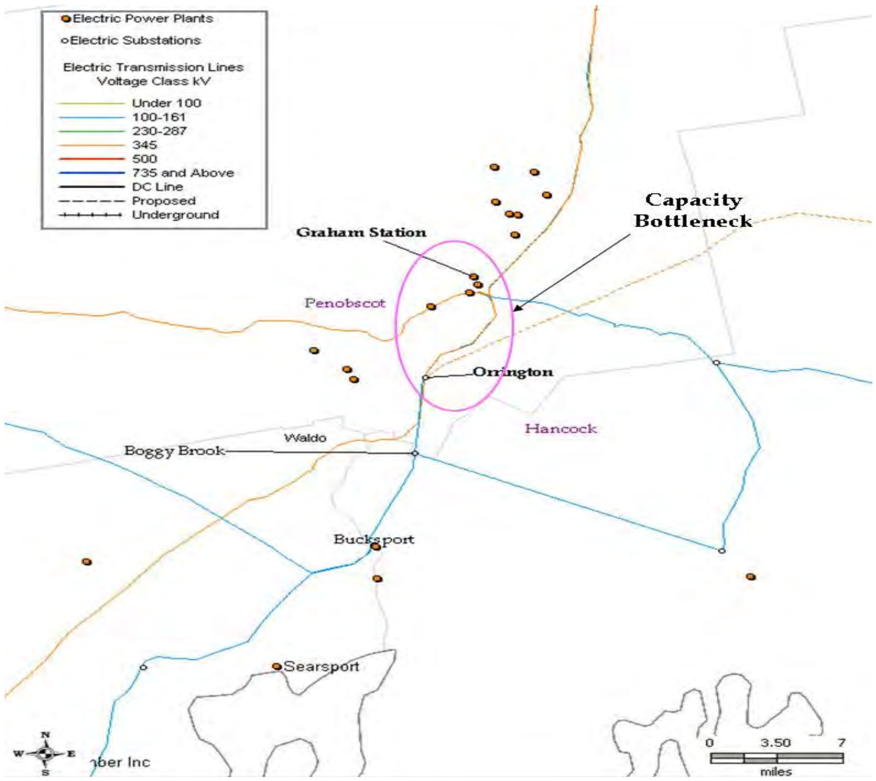
First, a capacity bottleneck exists on Line 64 south to Graham Station and onto Orrington Substation when generations levels were increased (see the figure below for illustration of these constrained transmission elements). When a sustained outage happens on Line 64, the company is unable to adequately supply sufficient power flow from Graham Station via its 46 kV transmission assets to this region of its service territory and must rely upon local generators to provide the electrical power to affected customers via the Company's non-bulk power system transmission system. BHE is examining the feasibility of constructing a new tie between Keene Road Substation and MEPCO Line 396 to reduce the southward power flow on Line 64, to enable the increased generation of electrical power in the northern and eastern regions of Maine, and to allow for eventual rebuild and rerating of Line 64.[127] BHE's reliability report also acknowledged that modifications to the Chester SVC facility are required to be able to accommodate the transformation.

[125] *Source:* BHE Company website.

[126] BHE Filing to the MPUC, September 7, 2007, page 8.

[127] BHE Filing, page 11.

Figure 38. Graham station to Orrington substation



Map created using Energy Velocity Suite (Accessed October 26, 2007

Second, BHE revealed that during peak load levels, power consumption in the Downeast region of its service territory could exceed the amount that can be sourced through local generation or increasing power flow from other lines, which could lead to local service interruptions, outages.[128]

BHE has plans to construct a 35-mile long 115kV 30 MVA transmission line between its Hancock and Harrington substations. BHE believes that this will provide a second power flow source for Downeast customers, reduce loading on line 66 east of Rebel Hill, improve the effective availability of high voltage power to this region, and enable it to satisfy its Transmission Planning loss of load criterion.[129] Remote switching capability would also be added to Rebel Hill that would enable power flow to be diverted from Line 66 during outages on segment 2 or 3 and this would allow segment 1 on Line 66 to continue to assist in the delivery of electrical power to the Downeast Region (via line 67) and the new Downeast Reliability Improvement Project once completed.[130]

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[128] BHE Filing, page 9.

[129] BHE Filing, page 11.

[130] Ibid.

3.3.3 Maine Public Service Company

Maine Public Service ("MPS") serves energy to approximately 37,500 retail customers in a 3,600 square mile area in Northern Maine.[131] MPS owns approximately 377.76 circuit miles of transmission lines.[132] Three transmission lines connect MPS to New Brunswick, Canada: (1) a 100 MVA import rated interconnection between Flo's Inn and Beechwood, (2) a 64 MVA import rated interconnection at Tinker Station, and (3) a 56 MVA import rated interconnection from Iroquois to Madawaska.[133] In its filing for the 2007 Grid Reliability Report, the MPS incorporated the NMISA Assessment, which was discussed earlier in Section 3.2 of this Report.[134]

MPS Transmission Lines:

- Line 3470 –Ashland substation to Squa Pan Hydro
- Line 4407 –Mullen substation to Island Falls
- Line 4425 –Island Falls to Patten
- Line 6901 – eastern Canadian border near the Fort Fairfield/ Limestone town line continuing to south along the border
- Line 6903 – Limestone substation to Caribou substation
- Line 6904 – Fort Fairfield/Limestone town line to Limestone substation
- Line 6905 – Madawaska to Limestone substation
- Line 6908 – Fish River substation to Caribou substation
- Line 6909 – Madawaska to Fish River substation
- Line 6910 – Flo's Inn substation to Mullen substation
- Line 6911 – Caribou substation to new West Caribou substation
- Line 6912 – Flo's Inn to Caribou substation
- Line 6914 – Flo's Inn substation to Ashland substation
- Line 6915 – Flo's Inn to Preque Isle Switching station
- Line 6916 – Mars Hill switching substation to Mars Hill
- Line 6917 – Limestone Switching station to Pond substation
- Line 6920 – Runs parallel to and near line 6910
- Line 6928 – Ashland substation to Ashland Industrial Park
- Line 6930 – Caribou substation to Ashland substation
- Line 3855 – eastern Canadian border near the Easton/Mars Hill town line to Flo's Inn substation.

Source: Exhibit 1 (Summary of MPS Transmission Lines) of the NMISA Seven-Year Outlook

Generation

In its report, MPS concluded that the projected in-region resources combined with the transfer capability of the MPS system will be adequate to meet projected load from 2007 to 2013.[135]

Transmission

MPS disclosed that its own grid reliability depends critically on the Boralex wood facilities. It maintains that with the Boralex-Ashland and Boralex-Fairfield units operating, it would be able to meet its planning objectives even during light wind and low hydrology conditions.[136]

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131 MPS Company Facts and Figures 2006.

132 MPS website at www.mainepublicservice.com

133 MPS Transmission Planning Strawman, page 1.

134 MPS Filing to the MPUC, September 14, 2007, page 2.

135 Ibid.

136 MPS Filing, page 3.

However, the N-1-1[137] objective would not be reached if either one of the Boralex units was unavailable during a system peak in light wind/low hydro conditions. If both of the units are offline during light wind/low hydro conditions, the system would not be able to sustain even an N-1 situation on-peak.

Based on the study conducted by the MPS, the degradation in reliability due to the removal of the Boralex Sherman biomass plant would not be so great as to justify the cost of looping that part of the system with additional transmission facilities.

As discussed earlier, the MPS and CMP are proposing to construct the Maine Power Connection a high-voltage line connecting northern Maine and ISO-New England. According to the MPS' filing, this project will not only provide market access but will also address the reliability concerns in the MPS system.[138]

3.4 Conclusion

All of the studies covered in this section are optimistic that Maine will be able to meet its electricity demand in the future. As discussed in Section 2, Maine has more in-state generating capacity than necessary to meet its current and future demand. The excess in-state capacity makes Maine capable of exporting electricity to neighboring states and provinces.

However, the IOUs' reliability reports raised concerns about the future reliability of the existing wires grid in Maine – at both the transmission and distribution level. As described above, transmission constraints limit Maine's ability to export power and, in some instances, create local reliability concerns. Thermal overloads and voltage violations occur during the tests conducted by some of these studies, suggesting that Maine may have insufficient transmission infrastructure as well as transformation capabilities. Numerous transmission projects, such as the construction of new lines and system upgrades, are currently being studied and will be submitted to the MPUC for approval, at which time the MPUC will need to determine which projects should proceed.

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137 The first contingency is modeled as a long-term outage allowing the system operator to make adjustments to the system prior to sustaining the second contingency

138 MPS Filing, page 4.

4 Implication of the Forward Capacity Market

Although ISO-NE has had a capacity market that pre-dates the FCM, the FCM will create a higher level of explicit capacity costs for Maine ratepayers.[139] It is anticipated that ratepayers in Maine will be responsible for approximately 7.5% of the total capacity costs from the FCM, based on the current peak load share. In its forecasts, ISO-NE puts these costs at over $1.9 billion in 2010 and $2.5 billion in 2016 (for New England as a whole) in the latest RSP; therefore, these are not insignificant market costs. [140] In fact, ISO-NE's first ever FCA concluded with a market price of $4.50/kW-month on February 6, 2008, which at the acquired levels of capacity, would imply a slightly lower cost to Maine ratepayers than the forecast figure.[141] The FCM is a highly structured product market. Given the rules for how the auction functions, how prices are set, and how costs are then allocated across New England, there may be important implications for Maine in terms of how many and what kind of resources to develop in order to minimize the costs of FCM. This section of the Report discusses the history of the FCM and the expected costs for Maine customers. We also provide a brief discussion of key market rules for FCM, and suggested strategies for minimizing future costs of this market on Maine ratepayers.

4.1 History of the FCM process and Maine's position

The FCM has a long history that dates back to pre-Standard Market Design ("SMD"). In February 2003, NRG applied for emergency FERC approval of four Reliability-Must-Run agreements ("RMRs") for plants in Connecticut and the Southwest Connecticut previously negotiated with the system operator (then NEPOOL). FERC rejected the RMRs, instead introducing the Peaking Unit Safe Harbor ("PUSH") bidding mechanism, and directing ISO-NE to develop a proposal for a locational capacity market.

In response to this directive from FERC, ISO-NE filed its initial Locational Installed Capacity ("LICAP") proposal in March 2004. The proposal called for dividing New England into zones, with separate markets for capacity in each zone. The other notable feature of the proposal was a downward sloping "demand curve" (i.e., an administratively set price schedule) that presented the market-clearing capacity price as a function of the ratio of installed capacity to the capacity requirement for a region. The proposal was immediately protested by a large group of market

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[139] The capacity market is not a new concept. However, the previous ICAP market never resulted in such explicit and large magnitude costs to New England ratepayers.

[140] This report was written before the conclusion of the first Forward Capacity Auction (FCA). Therefore, we do not describe in detail the results of this first FCA. The capacity clearing price was $4.50/kW-month across the entire New England market, as that is the floor price specified in the Market Rules for the initial auctions. Although Maine was identified as an export-constrained region before the start of the auction, market rules stipulate that no region's price could not be any lower than the market defined floor price and therefore Maine received the same price as the rest of Pool. Additional information on the results of the first FCA are available at http://www.iso-ne.com/nwsiss/pr/2008/fca_prelim_results_02_06_08.pdf The basic structure and market rules have not changed now that the first FCA has occurred, therefore, the strategic implication of the Forward Capacity Market and hedging of costs from the FCM discussed in the report still hold.

[141] *See* http://www.iso-ne.com/nwsiss/pr/2008/fca_prelim_results_02_06_08.pdf

participants, including state representatives in Massachusetts, Connecticut and Maine, as well as generators and utilities. A series of hearing and appeals followed.

After a series of hearings that began in June 2004, an administrative law judge ("ALJ") in June 2005 upheld ISO-NE's LICAP proposal (with minor modifications) as an appropriate market model. Implementation, however, was deferred until early 2006. In October 2005, after a series of oral hearings about LICAP, FERC invited parties that were still unhappy about the ALJ-approved LICAP proposal to submit alternative ideas for capacity mechanisms in New England. FERC agreed to allow the various parties ("Settling Parties") to enter into a settlement process, with a settlement deadline of January 31, 2006. After the input of numerous parties, including the introduction of entirely new proposals, a settlement was predominantly finished by the January 31st deadline. An extension was granted to continue negotiations on a number of details, with the Settlement Agreement[142] filed on March 6, 2006. FERC approved the Settlement Agreement on June 16, 2006. To implement the Settlement Agreement, ISO-NE and the NEPOOL filed the Forward Capacity Market rules ("FCM Rules") with FERC on February 15, 2007, which FERC approved on April 2007. ISO-NE filed with FERC the informational filing for qualification in the Forward Capacity Market ("Information Filing")[143] on November 6, 2007 per Section III.13.8.1 of the FCM Rules.

During this settlement process in 2006, the MPUC and the Maine Public Advocate ("MPA") objected to the Settlement Agreement. Their objections focused on two key arguments. First, MPUC and MPA believed that the Settlement Agreement does not do enough to address the issue of location (especially during the transition period); and second, the Settlement Agreement does not address Maine's unique circumstances, and thus will impose an unacceptable burden on Maine's economy. Furthermore, the MPUC and MPA argued that the settling parties had not adequately justified their positions (as they have only submitted two

142 The Settlement Agreement proposed a forward market for capacity, where capacity would be procured in advance. With the exception of the first auction, the Forward Capacity Auction would take place three and a half years ahead of the Commitment Period, with Reconfiguration Auctions annually thereafter; and seasonally and monthly (when in the Commitment Period).

143 According to Section III. 13.8.1, ISO should make an information filing with FERC detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination: 1) which Capacity Zones shall be modeled in the Forward Capacity Auction ("FCA"); 2) the transmission interface limits used in the process of selecting which Capacity Zones shall be modeled in the FCA; 3) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the FCA; 4) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the FCA, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone; 5) the multipliers applied in determining the Capacity Value of a Demand Resource; 6) which resources are accepted and rejected in the qualification process to participate in the FCA; 7) the Internal Market Monitoring Unit's determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids based on the Internal Market Monitoring Unit review and the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitoring Unit.

affidavits). The Maine parties recommended a minimum of three adjustments to the Settlement Agreement:[144]

- a $2/kW-month transition payment for the Maine zone (as compared to prices ranging from $3.05/kW-month in the first transition year to $4.10/kW-month in the final transition year proposed in the Settlement);
- an auction-based (as opposed to engineering-based) determination about which import constraints are binding; and
- a Cost of New Entry of $6.50/kW-month in the Maine zone.

In summary, MPUC, Maine's industrial consumers and MPA all believe that the Settlement Agreement imposes a significant and unjustified burden on Maine's economy. Maine even threatened to pull out of ISO-NE entirely if the Settlement Agreement was accepted without changes.

Despite the ongoing opposition from various parties to the market design choices, the FCM has indeed successfully attracted new investment. The ISO in November 2006 began seeking "show of interest" applications to gauge possible auction participation for the first Forward Capacity Auction ("FCA") to be held in February 2008 (for commitments to the 2009-2010 capability period. Since November 2006, ISO-NE has received more than 400 applications that total "well over" 17,200 MW.[145] As of May 25, 2007, several hundred of demand resources, representing 2,449 MW have expressed interest in the first FCA.[146] And on the basis of the November 6, 2007 filing by ISO-NE with FERC, a total of 3,758 MW New Generation Capacity Resources were qualified for the first FCA[147], including one wind project located in Maine (KIBBY WIND FARM) with a summer capacity of 20.4 MW and winter capacity of 47.3 MW. 190 New Demand Resources totaling 2,483 MW[148] of capacity are qualified to participate in the first FCA and about 234 MW is located in Maine.

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144 The Maine parties also supplied an affidavit supporting their position by Thomas D. Austin, an economist for the MPUC.

145 This includes more than 15,000 MW of supply-side resources from traditional generation resources, including renewables, imports, and over 2,200 MW of demand-side resources such as energy efficiency, load management, and distributed generation. http://www.iso-ne.com/nwsiss/pr/2007/fcm_soi_results_03-16-2007.pdf

146 ISO-NE, RSP 2007, page 5.

147 ISO-NE Informational filing for qualification in the Forward Capacity Market ("Information Filing"), November 6, 2007, ISO-NE, page 6 .

148 Ibid. Note that the figure shown here reflects have made various adjustments, including grossing-up actual demand reductions to reflect a credit for losses and reserves.

These resources, along with existing capacity, bided in the first FCA in February 2008. Section 7 on page 97 contains a brief description of the descending clock auction process which will be employed by ISO-NE for each auction.

As mentioned above, the first FCA cleared at the administrative floor price ($4.50/kW-month) with excess supply of 2,047 MW. Even though Maine was designated an export-constrained zone, the export-constrained zone designation did not bind the price outcomes of this auction. As a result, there was only one capacity clearing price across New England. Notably, of the 626 MW of new supply-side resources that cleared this first FCA, none were located in Maine. In addition to the supply-side resources, about 1,188 MW of new demand-side resources cleared, including energy efficiency, demand response, and distributed generation.

Figure 39. Results of the first FCA

	New Supply-Side Resources	New Demand-Side Resources	Existing Supply-Side Resources	Existing Demand-Side Resources
Connecticut	354	238	6,835	610
Maine	-	170	3,244	103
Massachusetts	190	567	12,777	481
New Hampshire	10	64	4,083	54
Rhode Island	21	78	2,401	87
Vermont	50	71	900	30
Imports	-	-	934	-
Total	626	1,188	31,173	1,366

Source: ISO-NE website. See http://www.iso-ne.com/nwsiss/pr/2008/press_release_fcm_auction_results_02_13_08.pdf

4.2 Capacity Cost

According to ISO-NE in its RSP 2007, the capacity costs from the FCM are estimated at $1.9 billion in 2010 for the system as a whole, increasing to $2.5 billion in 2016.[149] These cost estimates are based on a net installed capacity requirement of 32,305 MW (33,705 MW minus 1,400 MW of Hydro-Quebec Installed Capacity Credit (HQICC)) in 2010 and 35,787 MW (37,187 MW minus 1,400 MW of HQICC) in 2016.[150] The cost to load in Maine will be $140 million in 2010 and $187 million in 2016, based on ISO-NE's load projections (see Figure 40 for more details).

Note that this calculation assumes that the capacity price in Maine is equal to the Rest of Pool, thus it represents the upper bound of the possible range of costs using ISO-NE figures – it is possible that Maine's capacity clearing prices will be lower which would mean a lower cost burden to Maine ratepayers. Indeed, in its latest filing to FERC, ISO-NE stated that Maine would be an export-constrained zone for the first FCA in February 2008. The potential for

[149] ISO-NE, RSP 2007, page 22.

[150] ISO-NE, RSP 2007, page 33.

reduced prices is an important element of the market rules and therefore is a core strategic element for Maine as it seeks to minimize wholesale power costs. We discuss the zone designation and price determination process for export-constrained zones in the next two sections.

Figure 40. Indicative capacity cost to load calculation for Maine ratepayers, based on ISO-NE forecast in RSP 2007

Year	ICAP requirement (MW)	ISO estimated capacity cost ($ million)	Implied capacity price ($/kW/month)	Capacity CTL to Maine ($ million)
2010	32,305	$1,900	$4.90	$140
2016	35,787	$2,500	$5.82	$187

Capacity Zone Peak Contribution Values (MW)

	2010	2016
Maine	2,146	2,388
Rest of Pool	26,888	29,493
Maine peak load share	7.4%	7.5%

Note: annual peak demand is based on CELT 2007 forecast

Note:

1) *Calculation of Capacity Requirement is based on Market Rule Section III.13.7.3.1*
2) *The table above was intended to demonstrate the magnitude of the capacity cost to load to Maine. The implied capacity prices of $4.90/kW-month in 2010 and $5.82/kW-month in 2016 were derived from the ISO-NE RSP 2007 published system- wide capacity costs. Please refer to ISO-NE RSP 2007, page 22.*

4.3 Capacity Zone determination

Market Rule Section III.12.2 states that prior to each FCA, the ISO should calculate the capacity requirement. The Local Sourcing Requirement ("LSR") shall represent the minimum amount of capacity that must be electrically located within an import-constrained Load Zone. The Maximum Capacity Limit ("MCL") shall represent the maximum amount of capacity that can be procured in an export-constrained Local Zone to meet the Installed Capacity Requirement.[151] Furthermore, Market Rule Section III.12.4 also points out that prior to each FCA, the ISO shall determine the Capacity Zones to be modeled in that FCA – each Capacity Zone will have its own auction and may have different clearing prices from each other.

For the Capacity Zone designation, Market Rule Section III.12.4 (b) states that "…if the total amount of capacity that is projected to be installed in the import-constrained Load Zone before

[151] ISO-NE published the ICR, LSR, and MCL for the 2010 to 2016 period. "*Representative Local Sourcing Requirements and Maximum Capacity Limits for 2011/2012-2016/2017*", Power Supply Planning Committee Meeting, October 22, 2007.

the start of the relevant Capacity Commitment Period is greater than the sum of that Load Zone's forecasted Local Sourcing Requirement…, the Load Zone shall not be modeled as a separate Capacity Zone in the Forward Capacity Auction. Otherwise, the import-constrained Load Zone shall be modeled as a separate Capacity Zone in the Forward Capacity Auction." In other words, if an import-constrained Load Zone's available capacity is lower than its LSR, then it is designed as an import-constrained Load Zone.

The ISO-NE Market Rule does not explicitly lay out similar guidelines for the determination of an export-constrained Load Zone. Conceptually, however, export-constrained Load Zones are areas within New England where the available resources, after serving local load, may exceed the area's transmission capability to export excess resource capacity. On that basis, there are two logical approaches for the export-constrained Load Zone designation process.

How does transmission affect designation?

Market Rule 1 Section III.12.2.2 states that:

$$\textbf{Maximum Capacity Limit} = \textbf{ICR} - \textbf{LSR}_{\text{rest of New England}}$$

Note that LSR $_{\text{rest of New England}}$ *is MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purpose of this calculation is treated as an import-constrained region. Additionally, the only transmission constraint to be modeled shall be the transmission interface limit between the Load Zone and the rest of New England Control Area.*

All things equal, the higher the LSR, the lower the MCL. A higher transmission interface limits (or transmission upgrades) tends to lower LSR as additional resources outside the Capacity Zone can help to meet the load in the Capacity Zone. A lower LSR means a higher MCL. The higher the MCL, the less likely a Capacity Zone would be designated as an export-constrained Load Zone given the same amount of generation resources in an export-constrained Load Zone.

First, as pointed out by the MPUC's FCM expert,[152] the methodology to determine whether Maine is an export-constrained Load Zone should logically produce results that are equivalent to analyzing whether Rest of Pool is an import-constrained zone. Using the above rule, if the Rest of Pool's LSR is higher than the available resources, then the Rest of Pool is an import-constrained Load Zone. By definition then, Maine is an export-constrained Load Zone.

Another approach relies on ISO-NE specifications of export capabilities. MCL is defined as the maximum amount of capacity that can be procured in an export-constrained Load Zone (i.e., Maine) to meet the system-wide ICR. Given the ICR is the total amount of resources that need to be purchased in New England, and the LSR for the Rest of New England is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be purchased within the export-constrained Load Zone, i.e. MCL. In other words, this is the amount of capacity that can be used to fully meet the needs within the export-constrained Load Zone plus that amount which can reasonably be expected to be exported from the Load Zone to

[152] Thomas D. Austin.

meet regional needs. If the available resource in an export-constrained Load Zone is higher than MCL, then some resources will not be able to be utilized for capacity purposes, resulting in an export-constrained Load Zone.

Per the FCM Rules, the ISO has made determinations with regard to the Capacity Zones earlier in November 2007. The ISO has determined that given the Local Sourcing Requirements and the capacity located in each zone, there are no import-constrained zones and therefore no Local Sourcing Requirements relevant to the FCA.[153] However, ISO-NE determined that Maine will be modeled as a separate, export-constrained zone in the first FCA. ISO-NE determined that Maine has a MCL of 3,855 MW, which is the maximum amount of capacity resources that can be procured from the Maine Capacity Zone. However, existing capacity in Maine exceeds that MCL. Therefore for the first FCA, two Capacity Zones will be modeled: Maine and Rest of Pool ("ROP").[154]

4.4 Implications of an export-constrained Load Zone

FCM employs a descending clock auction process. The auction starts simultaneously for all zones, with the Starting Price is set at two times the Cost of New Entry ("CONE"). The descending clock auction works in the way that as bids are withdrawn ("de-listed" in the FCM context), and the quantity of remaining MWs falls below the procurement targets (i.e., ICR for New England, MCL and LSR for Capacity Zones), the auction-clearing price and corresponding quantity are set at the last price where there was oversupply. In other words, if the amount of capacity bid at the Starting Price is greater than the procurement targets, the price declines until the amount of capacity offered is just equal to the amount being procured (with some nuanced adjustments based on the Pricing Rules). Effectively, there will be price separation (implicitly an effective separate auction) for a Capacity Zone if the procurement targets for rest of pool and that Capacity Zone are met at different auction rounds of the descending clock auction. Consequently, the price for the export-constrained zone could be lower than or equal to rest of pool ("ROP"), depending on the timing of the end of the descending clock auction for the export-constrained zone versus that of the ROP. If the ROP auction closes before the round of auction that meets Maine's MCL, then Maine would have a lower capacity price, creating price separation between the two zones. On the other hand, if the ROP auction closes at the same time as Maine, then there will only be one capacity price in New England.[155]

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[153] Specifically, in the Connecticut Load Zone, there are 7,637 MW of existing resources and the Local sourcing Requirement is 7,117 MW (including 100 MW of capacity that submitted an Administrative De-List Bid). In the NEMA Load Zone, the existing resources are 3,424 MW and the Local Sourcing Requirement is 2,246 MW. In other words, there is sufficient existing capacity in each potential import-constrained Load Zone, Connecticut and NEMA, so they will not be modeled as a separate Capacity Zones in the first FCA.

[154] *See* Information Filing, page 4. However, based on the ISO-NE press announcement on February 6, 2008, the clearing prices for Maine and ROP are the same, because of the binding nature of the pricing rule that defines the lowest possible price over the initial few auctions. See http://www.iso-ne.com/nwsiss/pr/2008/fca_prelim_results_02_06_08.pdf.

[155] *See* Market Rule 1, Section III.13.2.3.3.

On this basis, in order for Maine to secure lower prices directly through the auction, the following conditions need to be met:

1) Maine needs to be designated as an export-constrained Load Zone, which is best achieved by having as much installed capacity (and demand-side resources) as possible and the smallest MCL possible; and

2) Maine's auction needs to close after the auction for the Rest of Pool, which means that Maine generators continue to offer capacity as auction prices are lowered.

Both elements are self-reinforcing. The first condition requires that existing assets continue to operate, and new assets (generating or demand-side) are brought online to offset growth in the MCL over time (MCL will change if transmission expansions increase the thermal transfer capability between Maine and ROP). The second order condition then requires that Maine resources – existing and new – offer at lowest possible prices in the FCA. Long term contracts with existing and new generators can be structured to achieve these conditions.

If any of the above conditions is not met – either Maine is not an export-constrained zone or Maine's auction does not close after the Rest of Pool auction – the efforts made will still likely bear fruit. To the extent that Maine is not a separate zone and is part of the pool-wide auction, the more generation it has participating on a price-taking basis in the auction, the lower the capacity clearing price (holding all else constant and assuming that the Alternative Pricing Rules[156] are not triggered). If Maine has more demand-side resources that evolve over time than the rest of New England, it will also indirectly reduce its costs related to the FCM, because its load share will decline and it will be responsible for a smaller share of total procurement costs. In the example below, we have assumed that Maine has more aggressive demand-side resources compared to rest of New England (10% of Maine's peak load vs. 5% of Rest of New England's peak load). Figure 41 shows that the peak load share for Maine would decrease from 7.4% to 7.0% in 2010 and from 7.5% to 7.1% in 2016.

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[156] According to Market Rule 1, Section III.13.2.7.8, if system-wide or in any import-constrained Capacity Zone: (a) new capacity is needed in the relevant Power Year; (b) the FCA is competitive (that is, the FCA does not have Inadequate Supply or Insufficient Competition); and (c) at the Capacity Clearing Price the out-of-market new capacity purchases exceeds the required new entry, then the Capacity Clearing Price for that Capacity Zone will be raised to equal the lesser of: (1) the price at which the last New Capacity withdrew from the auction (excluding out-of-market bids and bids in export-constrained Capacity Zones) minus $0.01; or (2) CONE.

Figure 41. Hypothetical example of peak load share dynamics

	2010	2011	2012	2013	2014	2015	2016
2007 CELT peak load forecast							
Maine	2,146	2,197	2,242	2,282	2,322	2,356	2,388
Rest of New England	26,888	27,438	27,928	28,372	28,779	29,148	29,493
Peak load share for Maine	7.4%	7.4%	7.4%	7.4%	7.5%	7.5%	7.5%
load reduction in Maine due to increased demand-side resources (10% of the peak load in Maine)	215	220	224	228	232	236	239
load reduction in Rest of New England due to increased demand-side resources (5% of the peak load in Res of NE)	1,344	1,372	1,396	1,419	1,439	1,457	1,475
Hypothetical peak load forecast							
Maine	1,931	1,977	2,018	2,054	2,090	2,120	2,149
Rest of New England	25,544	26,066	26,532	26,953	27,340	27,691	28,018
Peak load share for Maine	7.0%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%

Following through this illustrative example, a relatively small peak load share reduction would reduce Maine's capacity cost to load by a few millions (in 2010) to as much as $9 million (by 2016), as shown in Figure 42.

Figure 42. Indicative capacity cost to load to Maine calculation under revised (hypothetical) peak load share

Year	ICAP requirement (MW)	ISO estimated capacity cost ($ million)	Implied capacity price ($/kW/month)	Capacity CTL to Maine ($ million)	Revised capacity CTL to Maine (due to lower % of peak load share for Maine) ($ million)
2010	32,305	$1,900	$4.90	$140	$134
2016	35,787	$2,500	$5.82	$187	$178

Note: The table above was intended to illustrate the magnitude and derivation of the capacity cost to load to Maine under various peak load share. The implied capacity prices of $4.90/kW-month in 2010 and $5.82/kW-month in 2016 were derived from the ISO-NE RSP 2007 published system- wide capacity cost forecast. Please refer to ISO-NE RSP 2007, page 22.

4.5 Minimizing costs of the capacity market

Given the objective of lower capacity prices for Maine consumers, we have developed several concrete strategies in light of Maine's existing installed capacity and transmission network and the ISO-NE market rules currently in place for the FCM. The proposed action plan for Maine aims at achieving the two conditions discussed above, which would likely result in a lower capacity-clearing price for Maine as compared to Rest of Pool. This would meet Maine's objective of minimizing its market cost exposure from FCM specifically and could also contribute to minimizing electricity rates to Maine consumers overall, depending on the implications certain actions would have on transmission and energy-related costs. These action items can be implemented in isolation, but would ensure higher likelihood of success if implemented integrally in conjunction with one another:

1) ***Insure maximum local capacity is available through firm contracts with capacity resources***: signing firm contracts with existing capacity resources can ensure their maximum availability and further maximize qualified capacity in Maine. In addition, the MPUC can also use such contracts to require existing capacity not to "delist" (effectively to act as a "price taker") so that the Maine auction ends after the Rest of Pool auction. Contracts can also motivate new capacity and contracts can be structured to require no de-listing to ensure the Maine auction will end after the Rest of Pool auction. Contracts would need to be customized to whether a resource was pre-existing or new, because there are different incentives for these resources, and their participation in the FCM and impact on price is also varied. Of course, for this to provide overall benefits to Maine consumers, the costs associated with the contracts must not exceed the FCM benefits.

2) ***Encourage improvement in plant operations to maintenance of high capacity rating***: since the ISO-NE's determination of qualified capacity is based on the most recent five years' rating, a higher capacity rating would increase Maine's qualified capacity. More qualified capacity makes the determination of an export-constrained designation more likely and increases the likelihood that the Maine auction settles after the Rest of Pool auction. Incentives for such performance can be embedded directly in contracts or other performance-based mechanisms. However, in designing the actual performance requirements, it will be important to ensure that the benefits of such contractual or performance arrangements are substantial enough to exceed the costs of administration, and, as noted above, that the associated costs do not exceed the FCM benefits.

3) ***Facilitate new generation with necessary transmission upgrades:*** transmission upgrades can help make capacity fully deliverable. ISO-NE noted in the most recent filing for the FCM that some of the new capacities that had submitted an application for qualification to participle in the first FCA were not qualified because necessary transmission upgrades would not be completed in time for new resource to be available.[157] A total of 13 projects totaling 1,658 MW were not qualified for the New Generating Capacity Resources in the first FCA as the result of interconnection studies. As an example, the Stetson Wind Farm with a summer capacity of 9 MW, in the Maine Load Zone, was among those rejected by ISO-NE. The overlapping impact analysis suggested that one interface in the Maine Load Zone would be overloaded after the addition of this project, and the related transmission upgrades cannot be ready by the start of the Capacity Commitment Period beginning June 1, 2010. Furthermore, for certain existing plants, it has been suggested that transmission upgrades would improve operations by removing constraints to export to rest of New England. Theoretically, with higher generation output, plants will able to earn more from the energy market and would therefore seek to recover a small share of their fixed costs

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[157] See Information Filing, page 8 and page 25.

from the FCM. This would then translate into lower bids in the FCA. Furthermore, higher generation profits could help avoid mothballing and plant closures and further ensure higher qualified capacity within Maine.

However, it is also important to note that transmission upgrades between Maine and the rest of New England may hurt Maine's export-constrained Load Zone designation, because the MCL is calculated with respect to transmission transfer levels between capacity zones. In other words, transmission upgrades in Maine to relieve congestion to the benefit of in-state generators may reduce or eliminate Maine's separation from Rest of Pool and the associated benefits to Maine consumers. Part of Maine's strategy, then, should involve inviting proposals from generators to mitigate these lost benefits, the objective being to further transmission development in a way that is mutually beneficial to in-state generators and loads.

Of course, to the extent that transmission is needed for local or regional reliability reasons, for e.g. to prevent voltage collapse and local outages, capacity cost increases associated with joining the rest of pool (and therefore receiving the pool-wide capacity clearing price) are likely to be outweighed by the risk-adjusted cost of outages. Finally, depending on the economic dynamics in the pool-wide auction given full participation by Maine's existing and newly-developed resources, there may in fact be a lower system-wide clearing price and therefore capacity benefits to Maine ratepayers, as well as other New England consumers.

4) ***Aggressive demand-side resource program***: Demand-side resources, like peak demand response programs, conservation (energy efficiency), as well as emergency response and distributed generation, are effectively treated on equal footing to conventional generating resources in the FCM. Therefore, more demand-side resource capacity is equivalent to more resources, for achieving the two conditions discussed above. Notably, demand-side resources are more valuable nominally in the FCM because they benefit from a sizable markup by ISO-NE for their minimizing impact on capacity margins and losses – unlike generation, they do not require additional reserve margins, nor do they increase transmission losses.

One MW of demand-side resource is more valuable than one MW of generation resources. Market Rule 1, Section III.13.7.1.5 provides the calculation for determining the Capacity Value for Demand Resource. For the first FCA, the calculation is based on the reserve margin and peak transmission and distribution losses from the 2007-2008 Power Year as specified in Market Rule 1, Section III.13.7.1.5.1. Therefore, the value of the ICR divided by the 50/50 summer system peak load forecast is equal to 1.143 and one plus the percent average avoided peak transmission and distribution losses is equal to 1.08. Therefore, the overall multiplier applied in determining the Capacity Value of a Demand Resource is equal to 1.223.[158] In other words, Demand Resource currently obtains a 22.3% mark-up in terms of qualified capacity as compared to generation. Therefore, 8.18 MW of Demand

[158] See Information Filing, page 12.

Resource is equivalent to 10 MW of generation resource. To the extent that one MW of nominal demand resource is just as expensive to develop as one MW of generating capacity, from the perspective of the capacity market, demand resources may be more cost-efficient.

Demand resources are also more scalable than conventional generation, which is especially important given that Maine is already in possession of surplus capacity and simply needs small, incremental quantities of capacity to maintain its Export-constrained Zone designation in the future.

More demand response can also indirectly affect Maine's costs from the FCM, as discussed above. As a separate zone, Maine's capacity cost to load is calculated as Maine's peak load share of the ICR[159]. Therefore, if Maine's peak demand grows slower than that of Rest of Pool (because of more demand response resources), then Maine's share of FCM costs will also be lower.

[159] FCM payments are based on the aggregate annual peak load of load serving entities (LSEs). On a statewide basis, this is effectively equivalent to the state's peak load share.

5 Implication of the Energy Market

The New England wholesale electric market is a multi-settlement energy market containing a Day-Ahead and a Real-Time market. New England is separated into eight load zones (Maine is one of them) and one hub, created to support bilateral trading and to represent the straight average of 32 nodal prices.[160] Since 2003, ISO-NE has used Locational Marginal Pricing ("LMP", or nodal pricing), a system designed to reveal the price of producing power at a specific location, explicitly taking into account the costs of transmission congestion and losses. In New England, there are over 900 pricing nodes, or points on the New England Transmission System at which LMPs are calculated. Maine's load pays for energy on the basis of a megawatt-weighted average of all nodal prices within the zone, called Maine zonal price.[161]

5.1 New England energy market foundation

The LMP represents the marginal cost of electricity at various locations on the New England transmission system based on economic dispatch. The LMP pricing mechanism enables the identification of areas of congestion and assigns the cost of that congestion to those locations. That way, markets and market participants can readily determine locations of congestion and understand the financial value of investing in generation, transmission, and load response programs in those locations.

The LMP pricing structure can be explained through the following equation:

LMP ($/MWh) = Energy component + Loss component + Congestion component

The energy component is the same for all locations. The loss component reflects the marginal cost of system losses specific to each location, while the congestion component represents the individual location's marginal transmission congestion cost.[162]

ISO-NE operates both a day-ahead and a real-time market. Although not exactly identical, the process of determining prices is similar in these two markets. The Day-Ahead ("DA") market represents the day before operating day, and its clearing process is used to generate LMPs. Generation, demand, external contracts, and increment and decrement positions that clear in the DA market settle at prices determined by day-ahead LMPs. The Real-Time ("RT") Market represents the actual operating day and balances supply and demand as the system operates. Real-time LMPs are based on current power system operating data. Deviations between day-ahead and actual real-time positions settle at prices determined by real-time LMPs.[163]

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160 ISO-NE, Presentation on Energy Markets: Overview of the Day-Ahead Market, 2007.

161 ISO-NE, Congestion Management under Standard Market Design, January 2003.

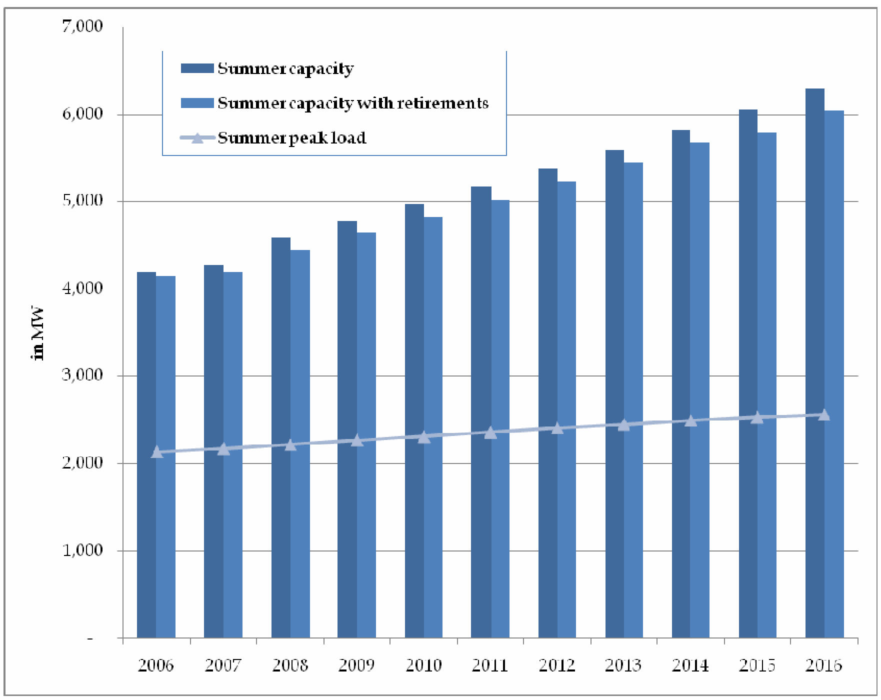
162 ISO-NE, LMP White Paper, February 2003.

163 Ibid.

The DA settlement is financially binding, providing price certainty and powerful incentives for RT performance. Because they are more indicative of the behavior of the various stakeholders in the market and the majority of load settles on the basis of DA pricing, DA market pricing dynamics are more relevant for our analysis and will therefore be the focus of the discussion in this section and in the analyses of LMP trends.

As discussed in section 2, the state of Maine has had more than enough generation capacity to cover its energy load. The current outlook of the supply-demand balance in Maine suggests that internal resources (on an aggregate basis) will be sufficient to meet the increasing demand in the state for at least the next ten years (see Figure 43). In our estimates, we have assumed that announced projects will be completed and will enter the generation fleet.[164] In addition, for illustrative purposes, we have produced another summer capacity variable that assumes that non-hydro plants will be retired after 50 years of service, reducing the forecasted resource base in Maine by 260 MW in 2016. The diagram shows that even if we do take into account potential retirements, Maine's in-state resources are still largely adequate for its energy load.

Figure 43. Projected Supply-demand balance in Maine, 2006-2016



Notes: Summer capacity with retirements represents the existing summer capacity, including confirmed announced entry, less the capacity of non-hydro plants that will be exceeding the age of 50. This table includes Northern Maine. *Source: Summer peak load: ISO-NE forecast and NMISA data; Summer capacity: CELT and NMISA data*

[164] The only exception to this rule is the Aroostood Wind Energy plant, which we have not included in the above figure. This plant is estimated to reach 500 MW, but is still in preliminary stages of development.

5.2 Locational Marginal Pricing in New England

With the identification of energy prices, losses and congestion of producing power at specific locations on the network, LMPs allow stakeholders to determine the financial value of investing in generation, transmission, and load response programs at these particular points. This approach lets generators interpret price signals, providing incentives for investment in new power plants and efficient transmission system expansion along the entire regional network, thereby reducing the total cost of electricity production.[165] From this perspective, a study of LMPs in New England is critical in providing the reader with the knowledge necessary to conduct an appropriate resource adequacy plan for the state of Maine.

5.2.1 Overview of LMP trends

LMPs are developed based on the bids of the resources in the energy market, taking into account physical constraints like transmission, congestion and losses using ISO-NE's security constrained economic dispatch model, which identifies the set of resources that would meet the system's load on a least cost basis. At its heart, the energy component of LMPs is a function of supply, demand, and fuel prices, implying that if demand rises while supply is static, then LMPs should also rise (and vice versa). The other components of LMP – congestion and losses – are also a function of energy component pricing determinants, but take into account the technical aspects of generation and transmission.

Figure 44 illustrates LMP trends for Maine and the Internal New England Hub ("Hub") for the past three years.[166] It shows that throughout this period, LMPs in Maine were, on average, lower than at the Hub, due to congestion and losses. The Hub has experienced higher prices at the maximum than Maine, while Maine has seen lower prices at the minimum (with the exception of 2006). The volatility of hourly prices, as measured by the coefficient of variation, has been consistently higher at the Hub than in Maine.

Figure 44. Trends in Hourly Day Ahead Locational Marginal Prices ($/MWh), 2005-2007

		2005		2006		2007	
		HUB	**Maine**	**HUB**	**Maine**	**HUB**	**Maine**
LMP	**Average**	$ 78.55	$ 70.82	$ 60.93	$ 57.13	$ 66.71	$ 62.39
	Max	$ 194.67	$ 183.89	$ 217.43	$ 191.46	$ 150.00	$ 142.50
	Min	$ 26.82	$ 12.85	$ 22.02	$ 22.03	$ 25.18	$ 24.41
	StdDev	$ 26.18	$ 23.49	$ 17.23	$ 15.27	$ 17.31	$ 15.52
	Coeff. of Var.	33.3%	33.2%	28.3%	26.7%	25.9%	24.9%

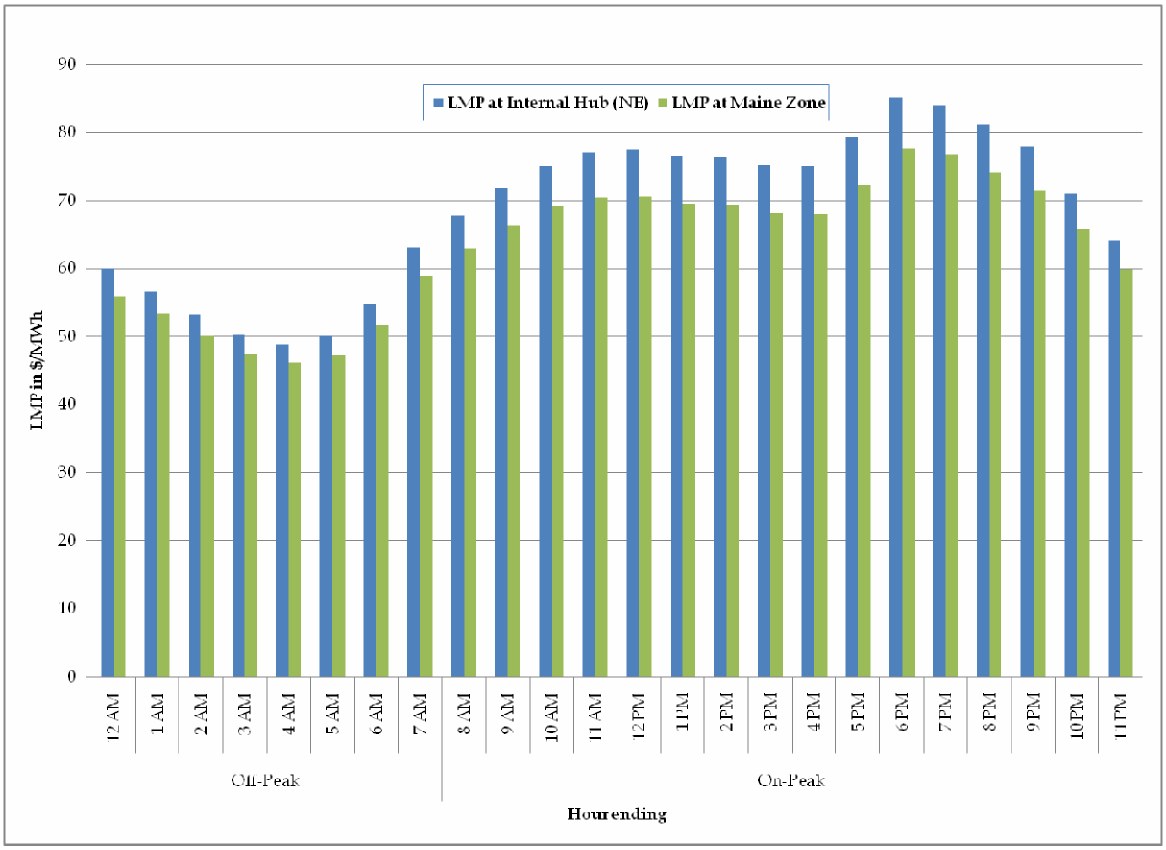
Note: Year 2007 only covers January – September

[165] Irish Commission for Energy Regulation, Briefing Note on the Proposed Market Arrangements in Electricity, 2003.

[166] The timeframe LEI studied covers the period January 2005 through September 2007.

More specifically, Figure 45 shows that the differences between the Hub and Maine were greater during peak rather than off-peak hours. The average hourly difference in LMPs was $3.26/MWh during on-peak hours compared to $2.73/MWh during off-peak hours on average over the entire sample period of January 2005 – September 2007.

Figure 45. Daily average Day-Ahead LMP prices, January 2005 – September 2007

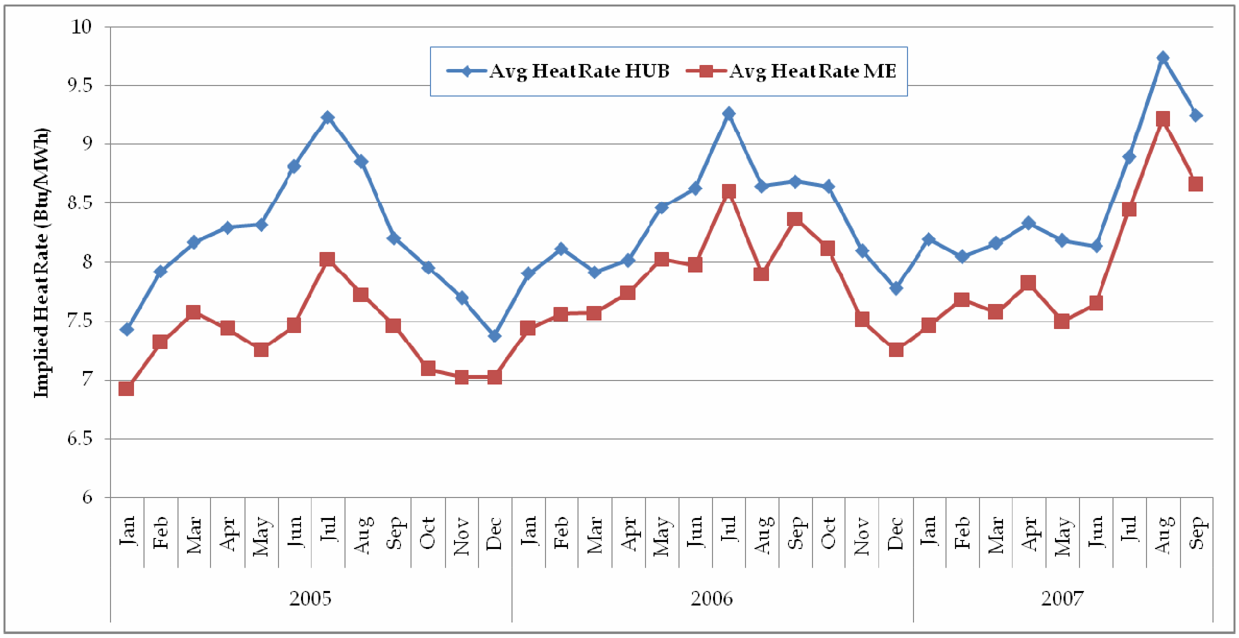


Source: Energy Velocity, 2005-2007

In order to isolate the gas price impact from electricity price fluctuations, we have analyzed the trend in LMPs normalized against gas prices. This is done by calculating the implied system heat rate, which is the ratio between average electricity prices and average natural gas prices. If the heat rate increases, it typically implies that the system is becoming less efficient (i.e., more expensive plants are price-setting), and the system is using the upper portions of the supply curve.

Figure 46 shows the implied heat rate calculated based on historical regional New England gas prices and historical LMPs at the internal hub and Maine. In general, the implied heat rate is not expected to change dramatically over time as the available capacity mix of generation is fixed. That being said, the implied heat rate is cyclical due to the seasonal profile of demand – it rises in the summer and generally declines in the winter months. For example, in July 2005, July 2006 and August 2007, the implied heat rate at both the Internal Hub and Maine rose dramatically, reflecting the ever-increasing summer peak load (mostly attributed to air-conditioning penetration). This increase in demand, combined with a static supply, led to an increase in LMPs which in turn led to an increase in the heat rate. Finally, we can notice from the graph that the average difference between the two heat rate curves decreased over time (from 0.83 Btu/MWh in 2005 to 0.55 Btu/MWh in 2007), with the Maine system appearing to be converging closer to that of the rest of New England.

Figure 46. Implied Heat Rate, January 2005 – September 2007



Source: Bloomberg; Prices based on ticker: USRENEWE NATGAS Regional New England

5.2.2 Congestion component

ISO-NE defines the congestion component of a LMP as the difference between the energy component and the cost of providing additional energy at that location, net of losses. When this difference is greater (or smaller) than zero, the next increment of energy is not able to flow from the least expensive generating unit to serve load in all locations. Thus, the system is required to bring in more expensive local generation to avoid overloading the network or violating operating criteria (e.g. voltage levels). Therefore, binding transmission constraints are the main factor for non-zero congestion values.[167,168] ISO-NE distinguishes between positive and

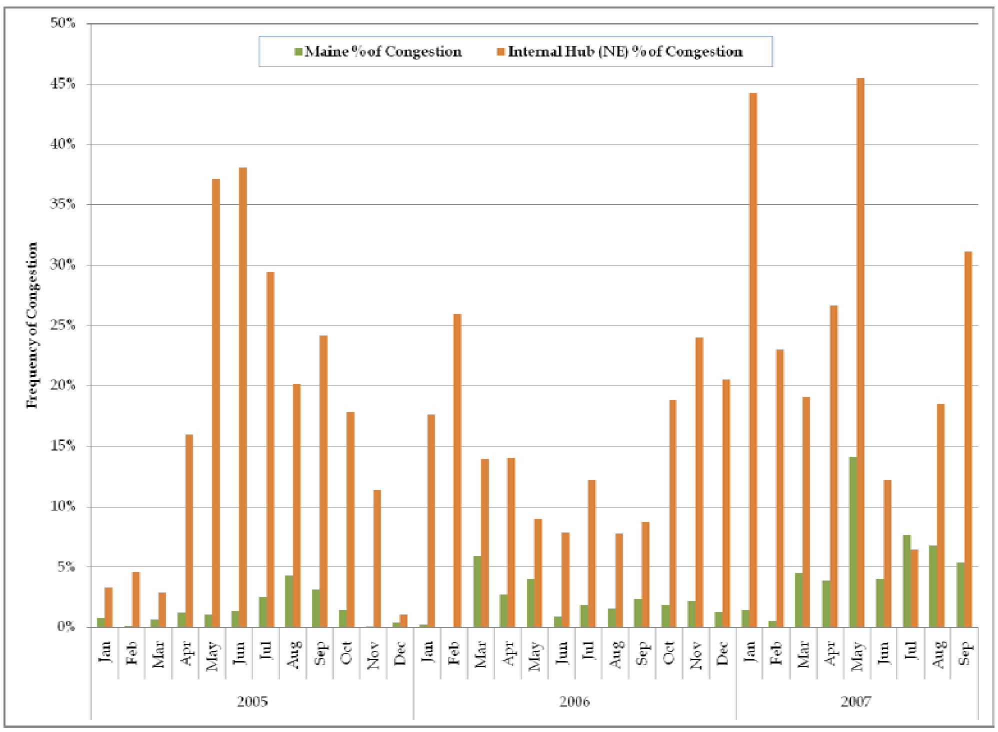
[167] ISO-NE, LMP White Paper, Feb. 2003

[168] The congestion component may also be influenced by increasing intrazonal congestion within Maine, a trend that is expected to be highlighted in ISO-NE's forthcoming "Second Maine Load Zone" study. This intrazonal congestion can be observed in Figure 15 on page 26 by looking at the increasing difference between nodal and zonal prices over time.

negative marginal costs of congestion depending on the location of the congestion: a positive congestion number at a specific node in Maine means that the congestion is greater in the rest of the system. On the other hand, if the congestion is negative, then the congestion is greater at the point of receipt than at the point of delivery.[169,170]

In Figure 47 and Figure 48 below, we can see that Maine has a higher negative congestion frequency than the New England internal hub, whereas its positive congestion is much lower than that of the Hub. While positive congestion reaches maxima of 14% and 45% for Maine and the Hub respectively, negative congestion reaches much higher levels, with 79% and 74% for Maine and the Hub respectively. In addition, there has been a noticeable drop in congestion in Q2 and Q3 of 2006 for positive congestion, and in Q1 and Q2 of 2006 for negative congestion. Finally, both positive and negative congestion have been increasing over the years in both Maine and the Hub, except for positive congestion at the Hub in 2006, which experienced the lowest average of the three years.

Figure 47. Frequency of positive congestion in Day Ahead LMPs by month, January 2005 – September 2007



Source: Energy Velocity, 2005-2007

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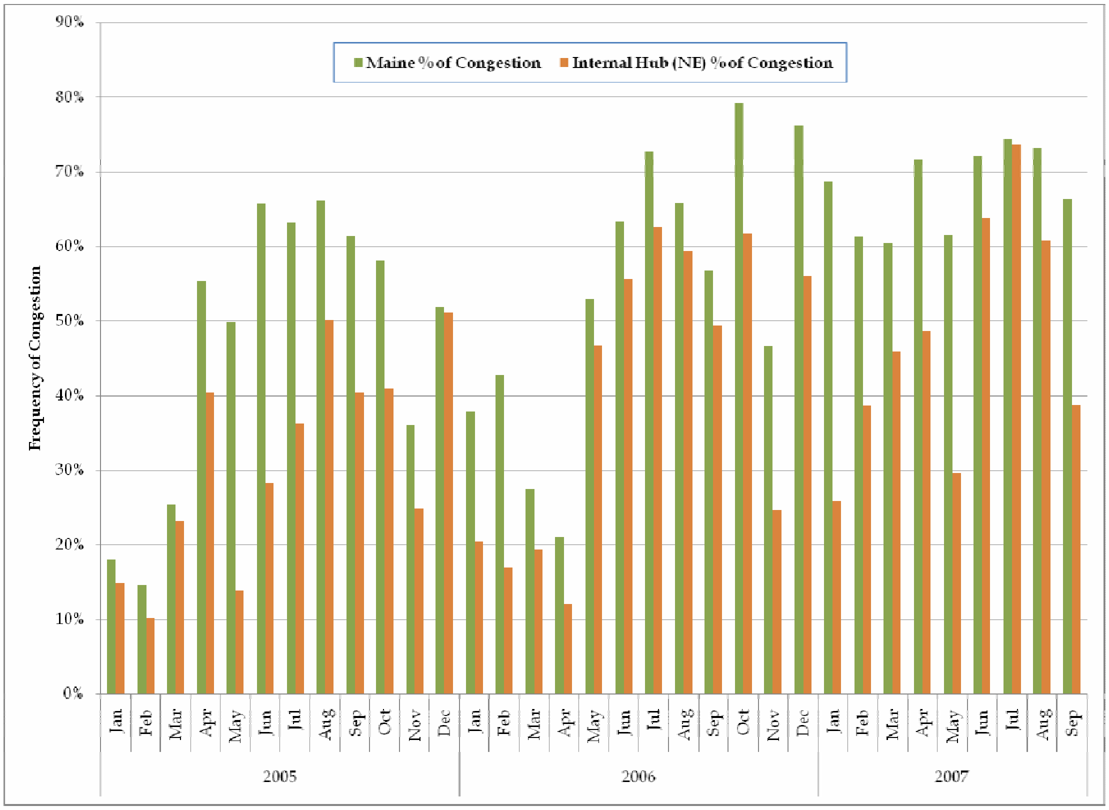
169 ISO-NE customer support, November 2007.

170 ISO-NE, Additional Invoice Details – Module 06: Financial Transmission Rights Market, June 2006.

Figure 48. Frequency of negative congestion in Day Ahead LMPs by month, January 2005–September 2007

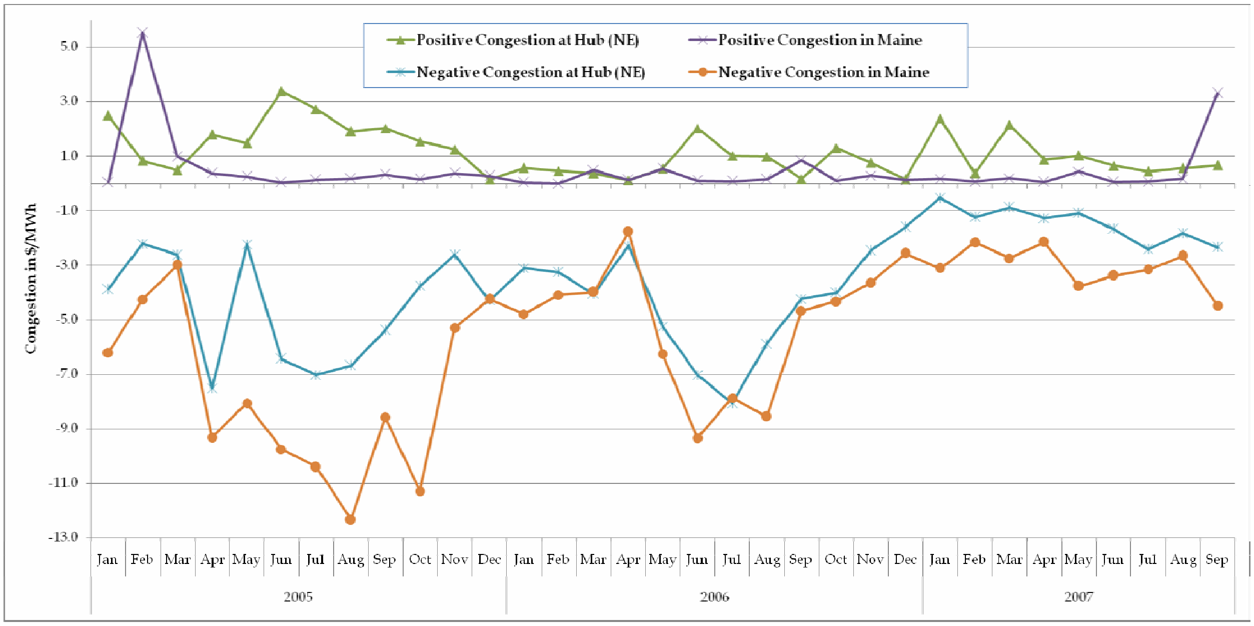


Source: Energy Velocity, 2005-2007

Figure 49 shows that the magnitude of negative congestion is higher in Maine than in New England's hub – which is not surprising given the known constraints in Maine. The internal hub's positive congestion is on average higher than Maine's (except for early 2005 and late 2007). More specifically, the average difference in positive congestion went from \$0.95/MWh in 2005 to \$0.46/MWh in 2006 to \$0.51/MWh in 2007. The average difference in negative congestion went from \$3.17/MWh in 2005 to \$0.89/MWh in 2006, and then rose again to \$1.59/MWh in 2007. In addition, the data for Maine and the Hub shows that frequency and magnitude of negative congestion are somewhat correlated: when congestion costs increase (become more negative), frequency tends to increase.[171] The same correlation holds true more loosely for positive congestion at the Hub. There is, however, no obvious trend in Maine, as positive congestion is minimal.

[171] This trend only applies for 2005-2006. Year 2007 (January-September) is an exception for both Maine and New England as there does not seem to be any obvious trend during this period.

Figure 49. Average monthly cost of congestion ($/MWh), January 2005 – September 2007



Source: Energy Velocity, 2005-2007

Finally, Figure 50 shows that the congestion differences between the internal hub and Maine are much greater during peak hours. The average hourly difference in congestion was $2.54/MWh during on-peak hours compared to $ 0.53/MWh during off-peak hours. At the same time, since congestion is a component of LMPs, it is also important to look at its proportional growth. Figure 51 clearly shows that although they generally follow the same growth pattern, congestion in Maine has been proportionally larger than at the Hub since January 2005, with a large increase in congestion during the summer months of 2005 and 2006. During the January 2005 to September 2007 period, the congestion accounted for 4.9% of LMP in Maine and 1.8% of LMP at the internal Hub. This overall level of congestion during peak hours confirms the severity of transmission congestion in Maine vis-à-vis the Rest of Pool, and confirms that it is correlated with higher demand periods, when Maine's generators are sending power southbound to meet demand in southern New England, and therefore congesting the system.

Figure 50. Congestion Costs in Average Day Ahead LMPs by hour ($/MWh), January 2005–September 2007

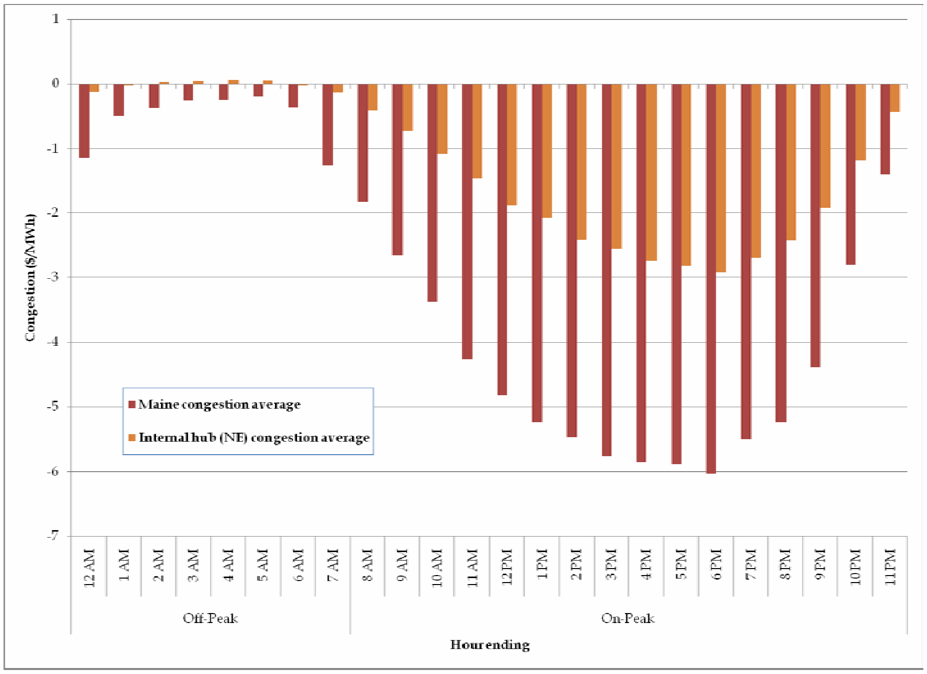
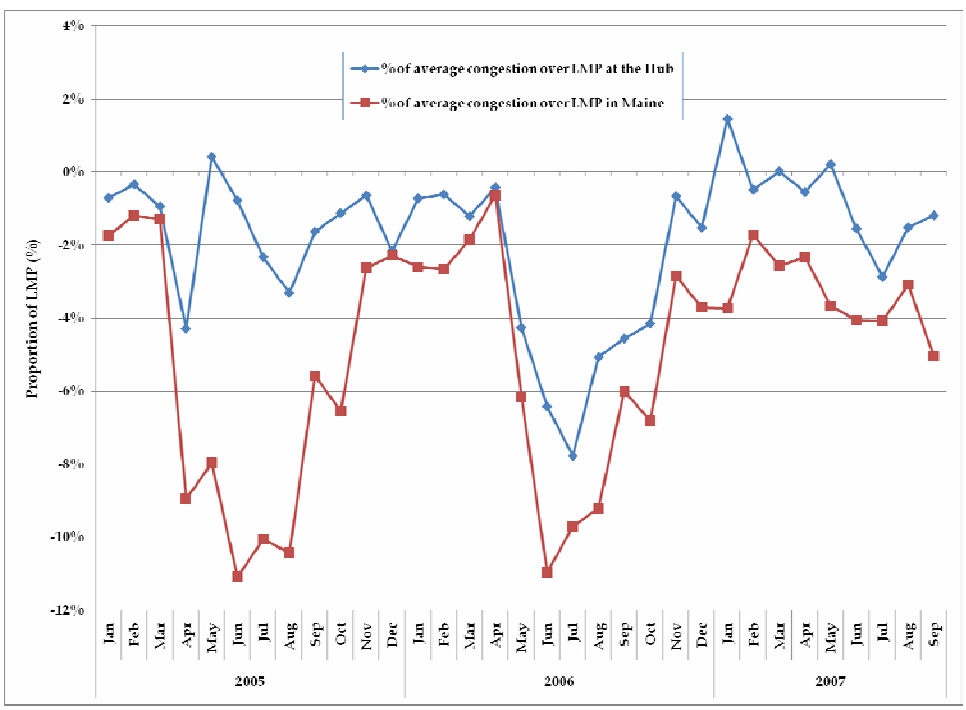


Figure 51. Proportion of average congestion costs in terms of Day Ahead LMPs by month (%), January 2005 – September 2007



Source: Energy Velocity, 2005-2007

5.2.3 Marginal losses component

An integral part of all electrical networks, marginal losses impact unit commitment, dispatch and pricing decisions by increasing operating costs for the system. In the New England LMP system, generators see their impact on losses through their nodal price, as do customers based on the zonal average LMP that they pay. The losses component is calculated with reference to a distributed market reference bus, which comprises all nodes that have associated loads within the NEPOOL control area. The distributed market reference allows the calculation of the loss factors to be less dependent on the location of the reference bus, promoting market fairness in calculating the loss component of LMP.[172]

Losses can bear either a positive or a negative sign, depending on the direction of flow away (+) or toward (-) the distributed reference bus. Since the flow of power in New England is predominantly from North-East to South-West,[173] LMP pricing nodes in the state of Maine tend to have a negative loss factor. Therefore, ignoring the cost of congestion, prices in Maine should have a lower price than the reference bus price, and prices in Southern New England states should have a higher price than the reference bus price (this is confirmed by Figure 45 above, which shows that the prices in Maine are lower than in the internal hub, located in the southern part of New England). This price differential represents the cost of moving power from the North-East to the South-West.[174]

Figure 52 shows that Maine exhibits mostly negative losses, while the New England internal hub has mostly positive ones.[175] After a significant increase in negative losses in the second half of 2005, Maine stabilized its losses and had a recurring pattern between 2006 and 2007: the losses increased during the summer months, and were at their lowest in the spring and the fall in absolute level terms.

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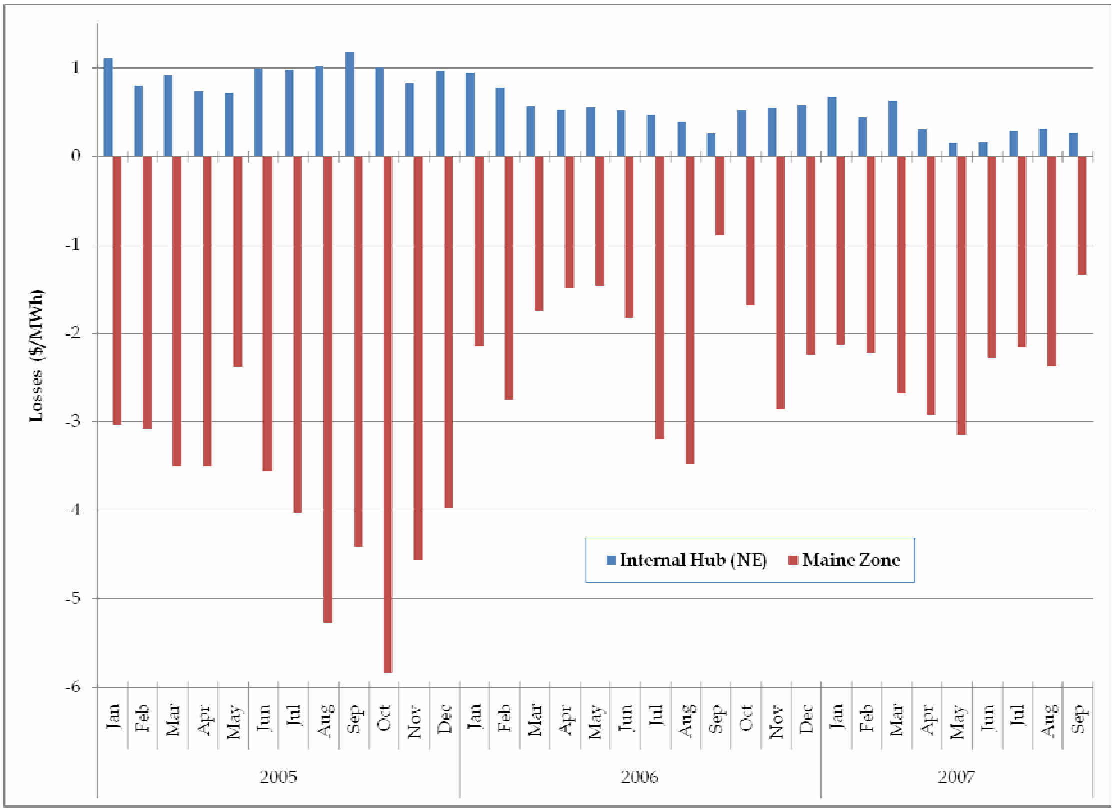
[172] ISO-NE, LMP White Paper, February 2003.

[173] ISO-NE, RSP 2007, page 77.

[174] This discussion follows a similar New York ISO analysis found in "The Importance of Marginal Loss Pricing in an RTO Environment", Liu and Zobian, October 2002.

[175] The losses calculated at a given node are related to (a function of) the total system losses that occur from the next increment of demand (or power injection) at that node. So, if load increases by 1 MW somewhere in Maine, it can cause an increase in transmission losses elsewhere in the system - due to the non-linear nature of power flows and the optimization of least cost dispatch across the entire system. Transmission losses are real, and are a function of the distance the power travels and its voltage. However, the losses that occur are not just from the next increment of power going from point A to point B. Serving that next increment of load (and presumably, incremental or decremental) may cause additional losses elsewhere on the system. Therefore, Maine could experience either positive or negative losses because total system losses may increase or decrease with each load increment - resulting in positive or negative marginal losses. It is also important to remember that these are "marginal losses", and are thus calculated based on serving each increment of load.

Figure 52. Average monthly losses at the Internal Hub and the Maine Zone ($/MWh), January 2005 – September 2007



Source: Energy Velocity, 2005-2007

In addition, Figure 53 shows that both Maine's and the Internal Hub's proportion of average losses in terms of LMPs decreased over time (they are both getting smaller in absolute percentage points). For Maine, the percent of transmission losses as a function of overall LMPs decreased from the 5% to 7% range in 2005 to about 4% in 2007. For the New England internal hub, the percent ratio of transmission loss component to overall LMPs decreased from 1.5% in 2005 to 0.5% in 2007.

In terms of frequency, Maine always exhibited negative losses, except during the summer and fall of 2006,[176] whereas the Hub always showed positive losses, except during the summer of 2007.[177] These results are not surprising given the description above. Maine has the greatest negative loss component, reflecting the fact that it is further away in terms of distance from the major load pockets in New England and reinforcing its relatively low cost generation mix, which is in demand.

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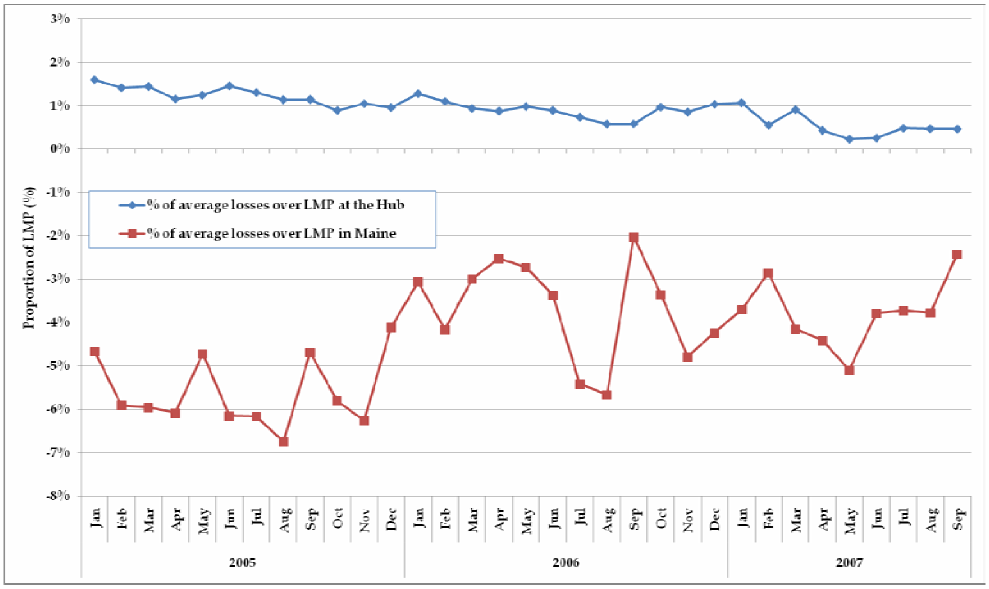
[176] During the summer of 2006, Maine showed negative losses 83% of the time in June, 87% in September and 93% in October.

[177] During the summer of 2007, the Hub showed positive losses 75% of the time in April and 81% of hours in May.

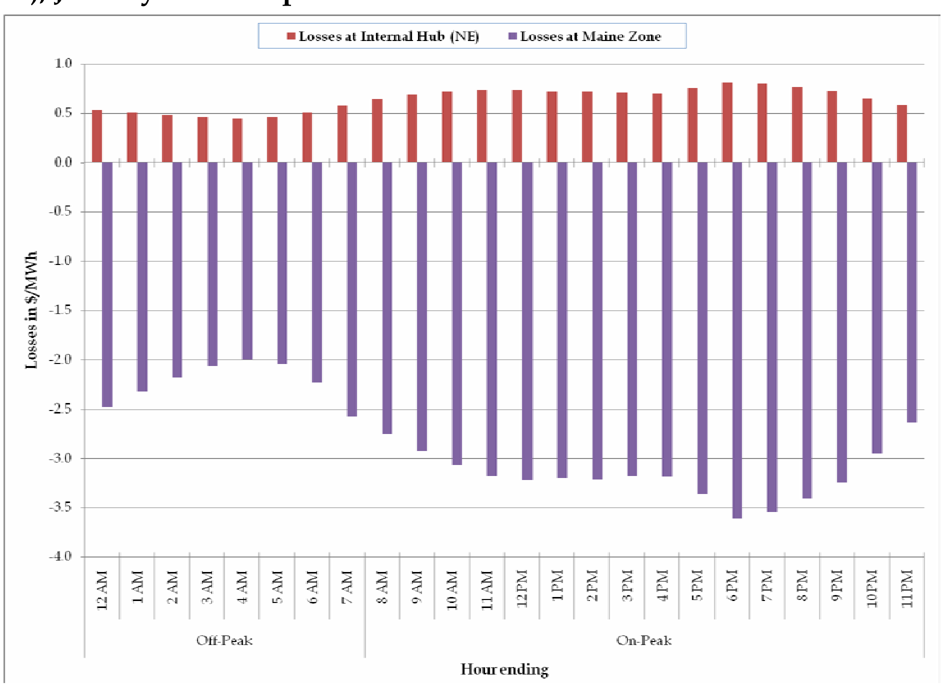
Figure 53. Proportion of average marginal losses in terms of Day Ahead LMPs by month (%), January 2005 – September 2007



Source: Energy Velocity, 2005-2007

Finally, as observed earlier with LMPs and congestion, Figure 54 shows the magnitude of marginal losses by hour in the DA LMP for the internal hub and Maine. Losses are greater during peak hours. The average hourly difference in losses between Maine and the internal hub was $3.88/MWh during on-peak hours compared to $ 2.73/MWh during off-peak hours.

Figure 54. Average marginal losses in Day Ahead LMPs for the Internal Hub and the Maine Zone ($/MWh), January 2005 – September 2007

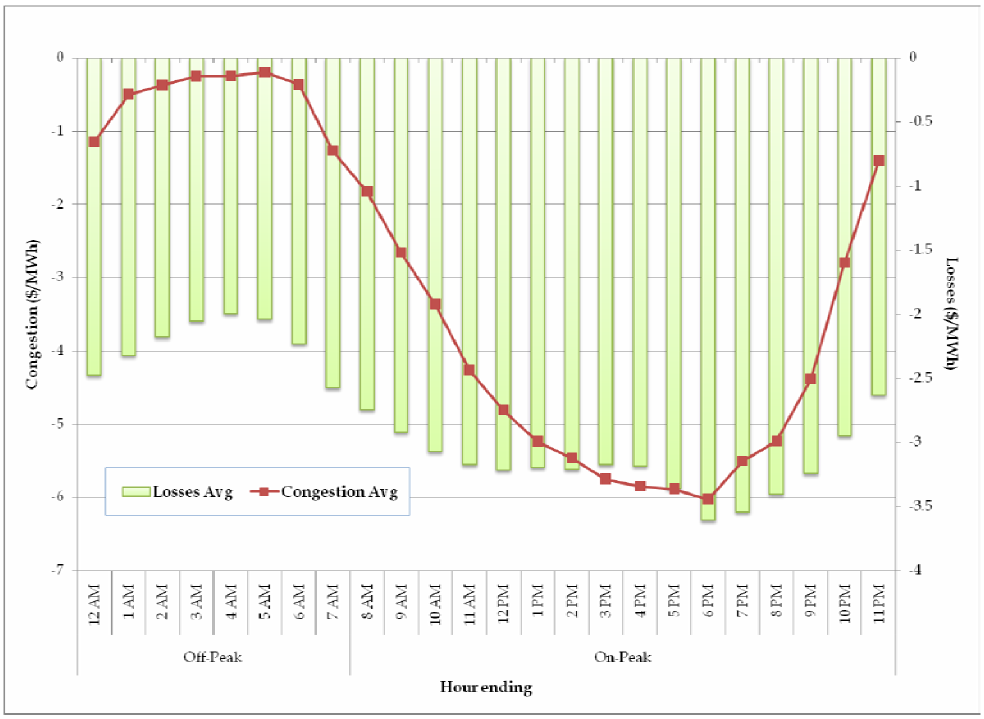


Source: Energy Velocity, 2005-2007

5.2.4 Congestion-losses trend analysis

In summary, both losses and congestion are larger during peak rather than off-peak hours in Maine. While congestion is generally more pronounced during on-peak periods, marginal losses remain relatively steady throughout the day. This result can also be seen in Figure 55 below, which shows that average congestion during peak and off-peak times were -$4.40 per MWh and -$0.54 per MWh respectively, while peak and off-peak losses were -$3.16 per MWh and -$2.23 per MWh respectively. In addition, this diagram shows that average hourly congestion and losses generally follow the same pattern throughout the day.

Figure 55. Average Hourly Congestion and Losses in Day Ahead LMPs for Maine ($/MWh), January 2005 – September 2007



Source: Energy Velocity, 2005-2007

5.2.5 Implication of new transmission investments

All components of LMP will react to new transmission investments. As discussed above, both congestion and losses in Maine are typically negative components to LMP, reflecting the constraints of the network and the overall distance of Maine resources from the New England load.

In general, the potential impact from new transmission investments should reduce congestion, meaning that LMPs would actually rise in the case of Maine (since its sign is generally negative). Maine would become more integrated into the rest of New England and would thus become more vulnerable to price fluctuations from other areas. On the other hand, increased transmission capacity may marginally reduce the energy cost component by allowing the ISO-NE to dispatch lower cost Maine resources more frequently.

Below, we have constructed three separate scenarios of possible outcomes of investment decisions in Maine:

1) ***Transmission expansion, with existing generation resources.*** Removing the current transmission constraints and allowing more electricity to flow out of Maine will depress both congestion and losses and render them less negative, thus raising overall LMPs, holding energy costs constant. Internal losses within Maine are expected to decline as higher voltage would allow the whole system to operate at a more efficient level.

2) ***Additional generation investment, without transmission expansion.*** Increasing generation without increasing transmission capacity will likely increase both congestion and losses (making them more negative). Although this will result in a lower LMP, it will effectively increase the already-existing risks and costs on the network, for example voltage problems as mentioned in Sections 3.1.1 and 3.1.2.

3) ***Transmission expansion, with additional generation investments.*** In this case, the change in congestion and losses will depend on the relative magnitude of the two investments, as additional generation investment could result in lower overall energy costs New England wide. Therefore, the price increase effect of lower congestion could be offset by the price decrease effect of lower overall generation costs.

As a result, we can see that the total outcome remains ambivalent in the short term depending on the interplay between the LMP components and the network's response to different types of investments. In the longer term, however, Maine ratepayers are likely to benefit from transmission investments to the extent that it would improve reliability of supply and make market operations more efficient. In addition, existing Maine generators should benefit from such investments as well, as they are likely going to be able to operate more frequently thanks to an expansion in transmission lines, potentially reducing energy losses and congestion. Finally, New England ratepayers may also see benefits in the form of lower overall energy prices, as a result of the influx of lower cost generation from Maine. In the longer term, with certain transmission projects, there are prospects of new low-cost, renewable generation being imported from Maine or through Maine, for the benefit of all New England ratepayers. To the extent that the best long term strategy for transmission expansion would impose costs on Maine consumers in the short term, these costs could be mitigated, for example, by contracts with in-state generators that directly benefit from the transmission expansion.

6 Conclusions and recommendations

The analysis in the previous section has revealed that LMPs, losses and congestion differences between the New England internal hub and Maine (with Maine always having a larger absolute and proportional value) were greater during peak rather than off-peak hours. Maine has generally benefited from lower LMPs because of the negative congestion and loss components. This means Maine ratepayers are paying less for energy than their counterparts in other parts of New England. However, existing generators in Maine are disadvantaged because they cannot economically compete with their peers in other parts of New England and are therefore producing less than they would otherwise due to congestion of the transmission system.

With time, Maine's energy prices have started to slowly converge with those of the rest of New England; the trend is apparent already, as seen by the implied system heat rate curves (see Figure 46). This convergence would be expedited to the extent that transmission reinforcements remove the current constraints and allow for more generation to flow southbound, providing potentially for more efficient market operations. The concrete benefit of transmission reinforcement will depend on the technical and economic nature of each project.

In Section 5, we discussed the potential impacts of generation and transmission investments on the energy market, while Section 4 reviewed the capacity market. These product markets cannot be viewed in an isolated fashion. In fact, capacity and energy markets are inter-linked as the generators try to maximize their revenues from the markets on a combined basis. In addition, both the energy and capacity market outcomes are contingent not only on the state of the generation sector, but also on the level and type of transmission investment made.

It is difficult at this stage to recommend a concrete set of policies and actions for the state of Maine. Resolution of certain future events, for example, selection, approval, and realization of transmission investment paths, and analysis of the impact of these events and other parallel market proceedings, such as the outcome of first FCA, are necessary before concluding on a specific set of options to pursue.

6.1 Interaction between capacity and energy markets

Below, in illustration of the inter-related nature of generation and transmission investment, we have presented five separate scenarios (extended from the three scenarios discussed at the conclusion of Section 5) on possible generation and transmission investments. Without judging why investment would take place, these five scenarios represent generally the various possible paths forward. We then discuss plausible outcomes in the energy and capacity market stemming from these various investment profiles. Without the benefit of information about which state of the world is more likely, it is impossible at this stage to develop a more detailed analysis of future outcomes. Once concrete proposals for transmission and/or generation investment become known, a more thorough cost-benefit analysis is possible.

1) ***Status Quo***. Assuming no investments are made on both transmission and generation, as load increases, the energy component of LMPs would increase (more expensive resources will be dispatched to meet the demand) while congestion and losses in Maine would

become more negative. Capacity prices would rise with higher ICRs, resulting from load growth. The net LMPs impact is unknown.

2) ***Transmission expansion, with existing generation resources.*** Removing the current transmission constraints and allowing more electricity to flow out of Maine will depress both congestion and losses and render them less negative. The energy component of LMPs may stay the same or may actually decline if there are sufficiently large increases in energy from Maine resources – or imports from Canada that employ the transmission expansion – that displace more expensive resources in the rest of New England. The net effect of these factors on Maine consumers will depend on the relative magnitude of the changes to each component of LMP.

   The movement of capacity prices in Maine under the above situation will depend on the investment decision with respect to transmission and generation:

   - if Maine is still designated as an export-constrained Load Zone and has its own auction, then capacity prices in Maine may decrease. As generators in Maine earn more from the energy market due to higher LMPs and/or higher generation output due to less congestion, they would bid lower in the capacity market and potentially lower capacity prices in Maine.

   - if Maine were no longer designated as an export-constrained Load Zone and becomes part of the Pool (which is a likely outcome given higher transmission interface limits between Maine and rest of New England as a result of the assumed transmission expansion), then the capacity costs in Maine may increase as Maine is required to take the price from the New England-wide auction. As a result, Maine will not be able earn a lower price than the rest of New England. However, the addition of Maine resources to the competitive pool of capacity for the FCA may put downward pressure on capacity prices system-wide, especially if Maine resources can offer more competitively than their peers located elsewhere in New England.

3) ***Additional generation investments (low cost resources), without transmission expansion.*** Increasing generation without increasing transmission capacity will likely increase both congestion and losses (making them more negative). If the resources added are cheaper generation resources (on the variable cost basis), like wind, the energy component would slightly decrease. Since there is no assumed transmission expansion, these new resources will primarily affect Maine prices, although during uncongested periods, they will also impact system-wide LMPs. In addition, the new low cost generation would displace existing generation to some degree, as a result of the transmission congestion.

   Additional local generation without transmission capacity expansion would likely support continued designation of Maine as an export-constrained zone for the FCM. Although this situation could result in lower LMPs in Maine, and lower capacity prices in the short-term (if price separation occurs in the auction process), the medium to longer term effects on capacity prices are unknown due to uncertainty in how bidding strategies in the FCM will evolve and how longer term investment decisions will be affected.

4) ***Additional generation investments but similar resources on the margin, without transmission expansion.*** This is the same as the scenario above but with milder effects on LMPs. Therefore, there would be no substantial impact on energy costs, and a risk for rising capacity costs, as discussed above.

5) ***Transmission expansion, with additional generation investments.*** This situation changes the paradigm for both energy and capacity costs in Maine. However, there is still some uncertainty in outcomes, and whether costs to load for Maine ratepayers rise or fall. The outcome depends on the precise circumstances of transmission and generation investment.

   In this case, the change in LMPs (and more specifically the change in congestion and losses) will depend on the relative magnitude of the two investments. As discussed above, lower cost generation can have a higher probability of lowering LMPs, even if transmission expansion leads to convergence of Maine and rest of New England energy prices. However, a lot of generation development, subsequently to transmission expansion, can again lead to transmission congestion, effectively re-establishing the current hedge that Maine enjoys from higher prices on-peak in the rest of New England. In order to determine which strategy is best for Maine, it will be important to analyze in more detail the nature of transmission investments and the viability of generation response. In order to complete this analysis, additional details are required on the nature and timing of transmission investment.

6.2 Recommendations

The future is likely to follow one of the paths outlined above. Without more certainty on the transmission investments, it is difficult to craft an optimal strategy for securing the least cost and most reliable electric supply. For example, the timing and character of transmission investment will influence the type of generation investment that is viable and economic, and also directly impact both the energy and capacity markets. Nonetheless, we have outlined a number of principle-level recommendations below.

Although additional resources are not needed *per se* in Maine, incremental demand-side resources should have a positive effect under almost all future market conditions. Indeed, an increase in peak demand relative to average demand due to air-conditioning penetration suggests increasing needs for peaking capacity and/or demand responses to meet those super peak hours that only occur a few hours a year. **Therefore, we recommend that demand side resources be encouraged to the maximum extent possible given their cost-effectiveness.**

In addition, as discussed above, it may be important to encourage lower cost (renewable) generation to be developed in Maine, but both the variable and fixed costs will have implications for Maine ratepayers given the introduction of the FCM. Variable costs of operation will affect the energy market, while the fixed costs will filter through the FCM. Section 2.5.1 has shown that the majority of new generation projects in Maine are wind projects, with effectively zero variable costs. However, wind developments are high capital cost undertakings and the developers would expect to cover their high capital costs, which will be reflected in the contracts they sign or their bidding in the FCM. A project might produce high gross benefits (large energy savings, in this particular example), but also carry with it large costs. **We recommend that a net benefit approach be employed to assess potential strategies, and specifically any resource contracts, so that different types of projects (with differing degrees of fixed and variable costs) can be evaluated on an equivalent basis.**

It is very difficult to recommend specific contracts and financial incentives for resources under this investment uncertainty because the costs of such arrangements will need to be weighed against the estimated benefits they will achieve in the market. The benefits of a contract can only be observed in the hypothetical from market outcomes: what would have happened if the contract was not executed? But even the costs of a contract are conditioned on the market outcome: if future market prices are low, then a contract is likely to appear costly, and vice versa. At the same time, it is important to recognize that the market outcome is contingent on the type of transmission investments undertaken, as well as other market drivers such as the state of future gas prices, level of competing generation development, demand growth, and future environmental regulation. A contingency problem arises, where generation and transmission investment complement each other, by depending on each other's development. The MPUC needs to determine the reliability and economic benefits of proposed transmission investments, and how such benefits trade-off with costs. There is a lot of uncertainty in how generators will respond to transmission investment, which makes measuring economic benefits difficult. **In order to reduce some of this uncertainty, it is possible, and indeed may be preferable, to analyze transmission projects' economic benefits concurrently with a long term contracting initiative for new generation.** For example, potential generators' responses to a competitive solicitation for long term contracts can provide a more definitive showing of economic benefits of transmission (as opposed to market price forecasting on the presumption of rational investor response), reducing risk and uncertainty for MPUC in the investment decision, while also possibly serving as conduit for defraying costs on Maine ratepayers from transmission investment.

It is also important to keep in mind that the net benefit analysis will depend on the objectives specified. The Act is specific in setting the parameters of the contract terms, but relies on a broad "least cost" principle. **We would recommend that an integrated market-wide approach be used, which quantifies savings across all ISO-NE markets, for e.g. capacity and energy, on Maine ratepayers.** Energy costs to load account for approximately 80% of the overall cost of power, while capacity accounts for only slightly over 15%. Therefore, if a contract can realize decreases in energy prices while increasing the capacity prices slightly, there will still be a net reduction of overall costs to ratepayers because the energy costs to load reductions will outweigh the increases in the costs to load from capacity.

Lastly, economic policy stresses the principle of "beneficiary pays" principle, because it allows for optimization of social welfare by reducing market failures such as externalities and "free rider" problems. To the maximum extent possible, we would recommend employing that principle in the structuring of arrangements to support low cost generation and associated transmission investment in Maine. To the extent that 'Rest of New England' ratepayers enjoy benefits associated with these investments, the costs of those investments should also be borne by these ratepayers. With modifications, the "Pooled Transmission Facility" approach in ISO-NE's transmission policy could provide a vehicle to implement this principle for transmission, and a parallel approach can also be taken to support generation investment. **We recommend**

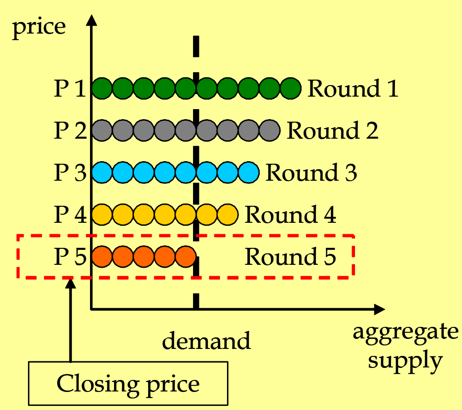
that state regulators and policymakers work with stakeholders to develop a framework for employing such a "beneficiary pays" principle.

7 Overview of auction process in FCM

The proposed auction process for the ISO-NE FCA

Involving a multi-run process, the FCA is anticipated to be a descending clock auction. The Starting Price is set at twice the Cost of New Entry (CONE). If the amount of capacity bid at the starting price is greater than the ICR or LSR (can be viewed as demand in FCM), the price declines until the amount of capacity offered is just equal to the amount being procured. In other words, as bids are withdrawn ("de-listed" in the FCM context), and the amount bid falls below the amount needed, the price and quantity are set at the last price where there was oversupply, i.e. P 5 under round 5 shown in the figure below. Note that the final procurement amount could slightly exceed the ICR or LSR (a situation the Settlement Agreement anticipates through the "Rationing Rule" found in section III.D.6 and the "Carry Forward Rule" in section III.J).

Figure 56. Illustration of a descending clock auction



All capacity that submits winning bids in the FCA is paid the capacity clearing price under normal conditions, but if there is not enough supply, or if there is a lack of competition in an FCA, special pricing rules will take effect for that particular FCA: New Capacity will receive the auction Starting Price and Existing Capacity will be paid 1.1 times the CONE in that auction year.