Maine Public Utilities Commission

2003 Annual Report on Electric Restructuring

Presented to the
Utilities and Energy Committee
December 31, 2003

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2003 Annual Report on Electric Restructuring

Report to the Utilities and Energy Committee
Developed Pursuant to 35-A M.R.S.A. §3217

I. BACKGROUND

During its 1997 session, the Legislature enacted P.L. 1997 (the Restructuring Act), ch. 306, codified at 35-A M.R.S.A. §3201-3217, which directed comprehensive restructuring of Maine's electric utility industry. Since then, the Public Utilities Commission (Commission) has disaggregated the vertically integrated electric utilities into delivery and generation functions, established the rates of transmission and distribution (T&D) utilities, established rules that govern the activities of competitive electricity providers and utilities, purchased standard offer service through competitive bid processes, monitored retail market development, and participated in regional wholesale market activities that affect Maine's electricity consumers. When compared with the experience in other states, Maine's retail market has developed smoothly and effectively in most respects.

Each year, pursuant to the Restructuring Act, the Commission submits a report to the Legislature's Joint Standing Committee on Utilities and Energy, describing Maine's retail market and activities the Commission has taken to comply with the restructuring statute. This report describes activities during 2003.

II. RETAIL MARKET ACTIVITY

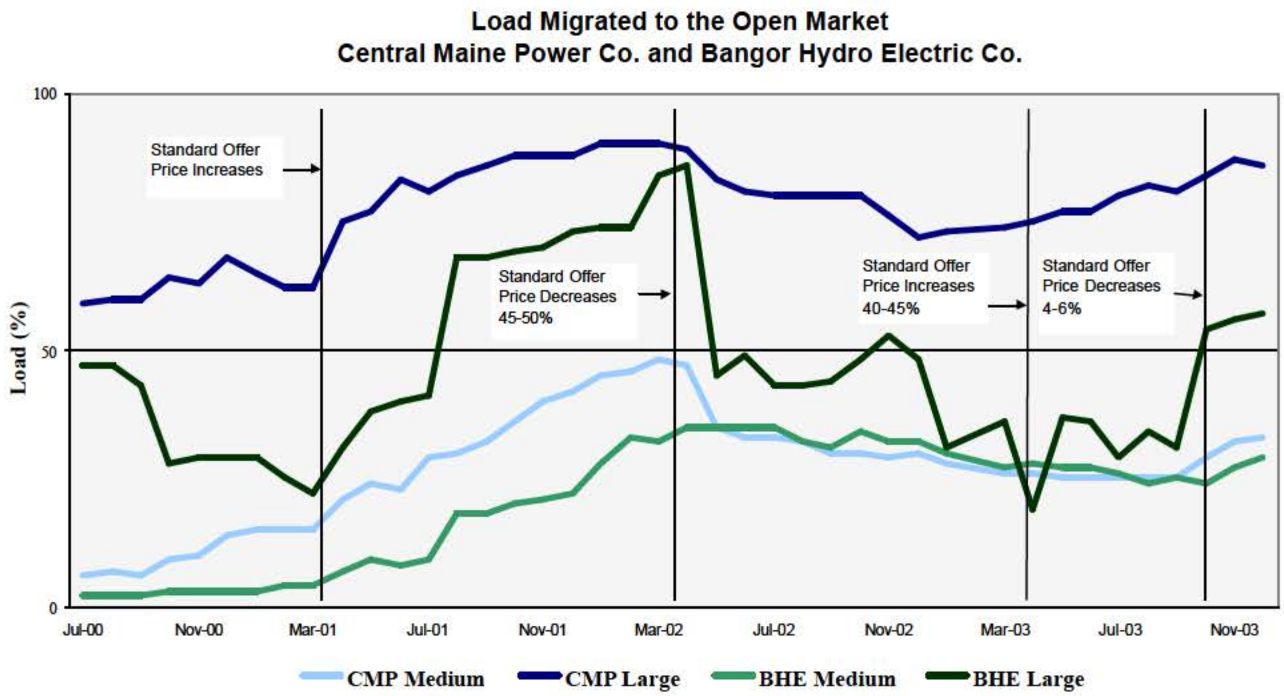
During 2003, the retail market for Maine's medium and large commercial and industrial (C&I) customers continued to exhibit a reasonable level of competitive activity, and bidding for standard offer service was healthy. The market continued to offer minimal competitive choice for residential and small commercial customers, but a low standard offer price obtained in previous years contributed to relatively low overall electricity prices. In addition, green products emerged that show promise of sustainability.

Migration from Standard Offer – Medium and Large Customers[1]

Migration from the standard offer to a competitive market supplier began with large business customers and extended over time to smaller business customers. After two years, the vast majority of large customers and a substantial number of medium customers had migrated from the standard offer. When customers' supply contracts expire, they may choose between a return to

[1] The Commission rules establish three standard offer classes: residential and small commercial, medium commercial and industrial (C&I), and large C&I.

standard offer service or an open market contract, based on their expectation of future market prices and their desire for price predictability.[2] While migration to and from the competitive market[3] is influenced to some extent by the relationship between standard offer and non-standard offer prices, the prevailing trend is for customers to remain in the open market once they have migrated from the standard offer. The graph below shows migration among CMP and BHE medium and large customers, and reflects an overall trend toward migration to the open



market.

The Commission has concluded that medium and large class standard offer prices should track wholesale prices as closely as possible, and, accordingly, we accepted bids for 6-month terms throughout 2003. Because of market fluctuations, in March 2003, standard offer prices for Bangor Hydro Electric Company (BHE) and Central Maine Power Company (CMP) customers increased significantly and in September 2003 they decreased slightly.

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[2] To avoid significant disruption to standard offer service load requirements, Commission rules prohibit customers that take standard offer service after being in the competitive market from discontinuing standard offer service within a year unless they pay an opt-out fee. Customers may petition the Commission for exemption from the fee, and a significant number have done so. The opt-out fee is intended to provide an incentive to remain on the open market.

[3] Standard offer service providers are chosen through a competitive bid process, so all customers receive service through the open market. For convenience, we often refer to non-standard-offer providers as competitive providers.

By early 2002, almost all of Maine Public Service Company's (MPS) large customers had migrated from standard offer service. This did not change in 2002 and 2003.

Migration from Standard Offer Service – Residential and Small Commercial

Acquisition and service costs for small customers are significant, and no substantial retail market has developed. However, because Maine's standard offer providers are chosen through competitive bidding based on price, all residential and small commercial customers are purchasing generation from competitive market suppliers, and vigorous competition among bidders for standard offer service has resulted in attractive standard offer service rates for smaller customers.

The northern Maine market has deviated from this pattern, with as many as 15% of MPS's smaller customers migrating to the competitive market. As discussed later in this report, during 2003, a competitive provider in northern Maine ceased to offer service to new customers, and customers subsequently began returning to standard offer service.[4] In CMP's and BHE's territories, fewer than one-tenth of one percent of customers have migrated from standard offer service. However, as discussed in the next section, migration may increase in the future.

Emergence of a Green Market

During 2003, "green" products began to appear through the actions of residential and public sector aggregation groups. These activities are showing early success at gaining customers and public recognition. In the residential and small commercial sectors, Maine Interfaith Power and Light (MIPL), a non-profit aggregator, began soliciting customers interested in receiving green power during 2002. In February 2003, these customers began receiving electric supply that was generated using 50% in-state hydroelectric and 50% in-state biomass fuel sources. The State of Maine provided public recognition when it contracted to purchase this product for over 700 State government buildings. In addition, through MIPL, customers may purchase "green tags" representing 99% wind and 1% solar generation.[5] By November 2003**,** in addition to the State purchase, 1,300 customers were purchasing the green power product and over 100 had purchased green tags.

[4] During the latter half of 2003, MPS discovered an ongoing reporting error in its small and medium customer migration statistics, so we do not show the migration statistics in this report. However, we estimate that almost 50% of residential and small commercial customers who had migrated to the competitive market returned to standard offer service between January and November 2003.

[5] A green tag purchases the credits that a supplier receives based on the fuel source of its generation.

An additional green product emerged for business customers in the education, health care, and non-profit sectors, when Maine Power Options, a non-profit aggregator representing these sectors, arranged for the provision of electricity produced solely from in-state biomass and hydroelectric facilities.

The table to the right shows the number and percentage of residential and small commercial customers[6] in CMP, BHE and MPS service territories who were receiving competitive market electric supply in December 2003. The numbers for CMP and BHE are up markedly from January's counts of 113 and 148, respectively.

Residential and Small Commercial Customers Migrated from Standard Offer

	number	percentage
CMP	1895	0.4%
BHE	402	0.4%
MPS	2882	8.0%

Northern Maine Retail Activity

The northern Maine region includes the service areas of MPS and three consumer-owned utilities: Houlton Water Company, Van Buren Light and Power District, and Eastern Maine Electric Cooperative.[7] In contrast to the rest of Maine, which is electrically part of the ISO-NE region, northern Maine is electrically part of the Canadian Maritimes region. The Maritimes region also includes the electric loads and generation of New Brunswick, Nova Scotia, and Prince Edward Island. Load and generation in northern Maine are connected to the rest of Maine and New England only by transmission through New Brunswick. Northern Maine load is supplied by a combination of generating plants located in-region and in New Brunswick. The Northern Maine Independent System Administration (NMISA) administers the bulk power and transmission systems for the region.

Although the retail market in the MPS service area appears fairly competitive, with about 52% of the load currently served by non-standard offer suppliers, there have been only two suppliers active in the northern Maine retail market since retail access began – Energy Atlantic (EA) and WPS Energy Services, Inc. In February 2003, Energy Atlantic announced that it would no longer accept new customers in northern Maine, although it would continue to provide service under existing contracts through their terms. EA cited deficiencies in the wholesale market and the small size of the market as the primary reasons for its withdrawal.

The experience to date and our discussions with suppliers indicate that others share EA's perspective. Measures that would make northern Maine part

[6] Residential and small commercial customers comprise the "small" standard offer class and their migration rates are combined for tracking purposes.
[7] Collectively, the customers of the four northern Maine utilities consume approximately 7% of the kWhs purchased in Maine.

of a larger market (e.g., a transmission line connecting northern Maine to the New England grid or an open market in New Brunswick) appear to be necessary to change this situation significantly. Appendix A provides additional discussion of these issues and describes activities the Commission has undertaken to improve the exchange of electricity between Canada and Maine generally.

During 2003, standard offer service prices in northern Maine continued to remain acceptable and stable, although the degree of supplier interest in competing to provide standard offer service remained less than in the CMP and BHE territories. An acceptable standard offer price mitigates to some degree the concerns resulting from the existence of only one active market participant in the region.

Retail Supplier Activity

Twenty-three suppliers of retail electricity are licensed to serve customers in Maine.[8] During 2003, twelve suppliers actively served customers. Three suppliers sold power to the residential market, while all suppliers sold power to medium and large C&I customers to some degree. CMP and BHE's C&I market shows a relatively healthy dispersion of sales among all suppliers. Well over half of the suppliers served more than 5% of the customers or load in either CMP or BHE's territory.[9] MPS's supplier activity is discussed elsewhere in this report. We have seen a level of consolidation among suppliers in the form of single entities owning multiple supply subsidiaries. However, this situation has not appeared to harm the vitality of Maine's retail market. We will continue to monitor this and all market conditions that affect Maine's consumers.

[8] The Restructuring Act authorizes the Commission to license suppliers before they may provide generation service to customers. In some instances, a licensed supplier owns its own generation, while in others, the supplier purchases its generation through the wholesale market. In addition, the Commission licenses aggregators and brokers, who assist customers in obtaining generation but do not supply the generation themselves. Twenty-three aggregators and brokers are currently licensed.

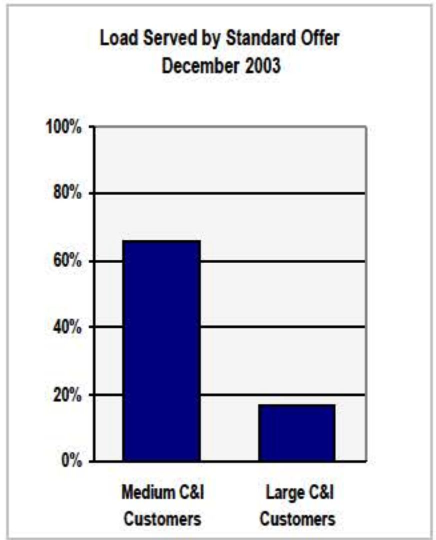
[9] Some suppliers serve a small number of large customers and thus serve a large percentage of load, while suppliers serving a larger number of smaller customers serve a smaller percentage of load.

III. STANDARD OFFER SERVICE

Overview of 2003

About 63% of the electric load in Maine currently receives standard offer service. This is slightly less than at the beginning of 2003, when about 68% of the load in Maine received standard offer service.

By customer class, standard offer service supplies about 66% of the load of medium commercial and industrial (C&I) customers and 17% of the load of large C&I customers in Maine, as shown by the graph on the right. Standard offer service continues to supply virtually all residential and small commercial customers, as has been the case since retail access began. By T&D service area, standard offer service supplies about 61% of the load of CMP customers, 76% of the load of BHE customers and 48% of the load of MPS customers.



The standard offer suppliers during 2003 and corresponding prices are summarized below. The prices shown here are averages; actual prices for the medium class may vary by month and for the large class by month and time of day. For more detailed prices, please see the Commission's web page at http://www.state.me.us/mpuc/new%20standard%20offer/standard_offer_rates.htm.

Average Standard Offer Prices in 2003

	Residential/Small Commercial		Medium C&I		Large C&I	
	Price ¢/kWh	Supplier	Price ¢/kWh	Supplier	Price ¢/kWh	Supplier
CMP						
Jan - Feb	4.95	Constellation	4.22	Select	4.24	Select
Mar - Aug	4.95	Constellation	5.91	FPL	6.11	Select
Sept - Dec	4.95	Constellation	5.57	FPL	5.74	Select
BHE						
Jan - Feb	5.0	Constellation	4.17	Select	4.01	Select
Mar - Aug	5.0	Constellation	5.86	FPL	5.75	Select
Sept - Dec	5.0	Constellation	5.62	FPL	5.43	Select
MPS						
Jan - Feb	5.69	WPS	5.73	WPS	6.13	WPS
Mar - Dec	5.80	WPS	5.85	WPS	6.25	WPS

Solicitations

The Commission held several solicitations for standard offer service during 2003. These solicitations were competitive and successful, resulting in retail standard offer suppliers and market-based prices for all customer classes. Suppliers continue to become more comfortable with Maine's retail standard offer service model, and the level of participation in our solicitations reflects this comfort.

The first solicitation of the year was for standard offer service for the CMP and BHE medium and large classes for the term beginning March 2003. The Commission issued RFPs in November 2002 and, in response, suppliers submitted indicative bid prices in December 2002. Staff and suppliers negotiated and resolved contract terms and, in January 2003, suppliers submitted final binding bids. After evaluating the final proposals, the Commission designated FPL Energy Power Marketing, Inc. (FPL) as the standard offer provider for the CMP and BHE medium classes and Select Energy, Inc. (Select) as the standard offer provider for the CMP and BHE large classes for the term March 1 through August 31, 2003. The Commission chose 6-month term bids for all four classes so that standard offer prices could more closely follow changes in market prices than would be possible, for instance, in the case of a 1-year term.[10]

The average prices for standard offer service during the March-August period based on the final bids are shown below:

Standard Offer – Term Beginning March 1, 2003

	CMP	BHE
Medium C&I	5.9 ¢/kWh	5.9 ¢/kWh
Large C&I	6.1 ¢/kWh	5.8 ¢/kWh

The second standard offer solicitation of the year was again for the CMP and BHE medium and large classes, for the term beginning September 2003. The Commission issued an RFP in early June 2003 and, after receiving indicative bids, negotiating contract and other non-price terms, and receiving final bids, again designated FPL and Select to serve the medium and large classes, respectively. The term was again set at six months (September-February) and the average prices were set as shown below:

[10] The Commission first accepted a six-month bid in March 2003. Six-month standard offer terms seem to work well for both non-standard offer suppliers, who have told us that a shorter term helps them attract customers, and standard offer suppliers, who have told us that the shorter term mitigates against load and market risk but is not so short as to discourage their participation.

Standard Offer – Term Beginning September 1, 2003

	CMP	BHE
Medium C&I	5.6 ¢/kWh	5.6 ¢/kWh
Large C&I	5.7 ¢/kWh	5.4 ¢/kWh

The third solicitation of 2003 was to acquire standard offer service for MPS customers. This solicitation covered all three standard offer classes for the term beginning March 2004. The Commission sought proposals for term lengths of 1 year and 34 months, the latter term to coincide with the end of MPS's purchased power contract with Wheelabrator-Sherman (W-S). MPS solicited bids to purchase its W-S entitlement in a concurrent RFP process, and standard offer-entitlement cross-contingent bids were explicitly allowed.

The MPS standard offer RFP was issued in September. Suppliers submitted indicative bids in mid-October, and staff and suppliers then negotiated and resolved contract and other non-price terms. Based on the final binding bids that suppliers submitted on November 3, the Commission designated WPS as the standard offer provider for all three MPS standard offer classes for a 34-month term, March 1, 2004 – December 31, 2006. The resulting standard offer prices are shown below:

MPS Standard Offer – Term Beginning March 1, 2004

Class	Price
Residential/Small Commercial	5.459 ¢/kWh
Medium C&I	5.810 ¢/kWh
Large C&I	6.400 ¢/kWh

WPS's standard offer bid was contingent on also receiving the Wheelabrator-Sherman entitlement at its bid price of, on average, 3.475¢/kWh for the same 34-month term.

The fourth and final standard offer solicitation of 2003 began with the release of RFPs on November 18. This solicitation, which is still ongoing, is to acquire standard offer service for the CMP and BHE medium and large classes for the term beginning March 2004.

A 3-year standard offer arrangement with Constellation Power Source Maine, LLC (Constellation) that began in March of 2002 continued to supply CMP and BHE residential and small commercial customers during 2003. The standard offer prices, 4.95 cents/kWh for CMP and 5.0 cents/kWh for BHE, will remain in effect through February 2005.

Consumer-owned Utilities (COUs)

COUs carry out bid processes to procure standard offer service in their territories. The following table displays their current standard offer prices:

Standard Offer Prices - Consumer-Owned Utilities

Utility	Price	Supplier
Eastern Maine Electric Cooperative	6.75 c/kWh	WPS
Houlton Water Company	5.387¢/kWh	WPS
Van Buren Light and Power	5.76 ¢/kWh	WPS
Fox Islands Electric Cooperative *	4.05 ¢/kWh	Exelon Power
Madison Electric Works *	6.604 ¢/kWh	Select
Swans Island Electric Cooperative *	3.5 ¢/kWh–5.7¢/kWh	Select
Kennebunk Light and Power Co. *	3.88 ¢/kWh	Exelon Power
Monhegan Electric	Exempt	
Matinicus Plantation Electric Co.	Exempt	
Isle au Haut	Exempt	

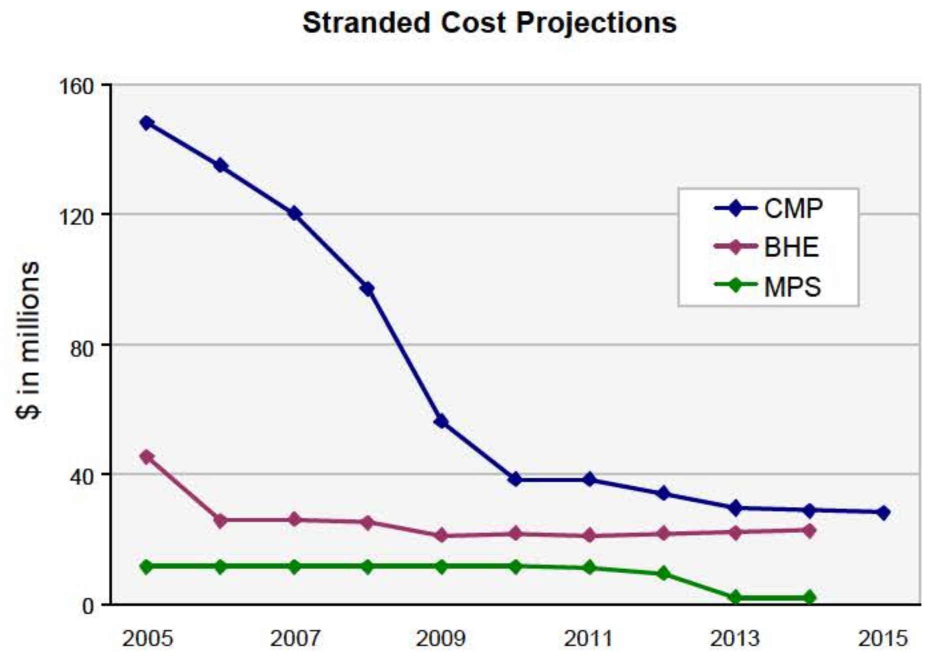
* Rate is approximate. It may vary monthly and is subject to a monthly true-up adjustment to reflect the actual costs of supply.

IV. STRANDED COSTS

The Restructuring Act allows CMP, BHE and MPS to recover stranded costs in the rates they charge for delivery service. Stranded costs reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring. For example, stranded costs include the difference between payments the utilities must make pursuant to pre-existing purchased power contracts (primarily with qualifying facilities (QFs)) and the current market value of that power.

Stranded cost rates are re-set for CMP, BHE and MPS approximately every two to three years. The adjustments coincide with the sale terms of the utilities' QF entitlements, because the amounts received from the entitlements sales offset stranded costs and are a significant component of total stranded cost rates. CMP and BHE stranded costs were re-set in 2002, while MPS's rates are being considered now for the period beginning March 1, 2004.

The most significant changes in stranded costs will occur when utilities' QF contracts expire. BHE's stranded costs will decline significantly in 2006, while CMP's will decline during the second half of the decade. Projections of stranded costs are shown in the chart below.



The major components of each utility's stranded costs over the year March 2003 – February 2004 are set forth below:

CMP	
QF contract costs	$254.3 million
Entitlement sale revenue	-102.3
Net QF stranded costs	$152.0
Closed nuclear plants	24.5
QF contract buyout	1.7
HQ tie-line	4.5
VT Yankee	1.4
Total stranded costs	**$184.1 million**

BHE	
Net QF costs	$28.3 million
QF contract buyouts	20.3
Seabrook	3.7
Other	-3.7
Total stranded costs	**48.6**

MPS	
QF contract costs	$11.5 million
Entitlement sale revenue	-4.1
Net QF stranded costs	7.4
Wheelabrator buydown	1.8
Seabrook	3.1
Maine Yankee	3.3
Deferred fuel	-4.3
Other	0.3
Total stranded costs	**11.5**

Until 2003, stranded costs also included, as an offset, the proceeds from the utilities' generation asset sales (referred to as the Asset Sale Gain Account or ASGA). In 2002, the ASGA offset CMP's and BHE's stranded costs by $43M and $5M respectively. However, in spring of 2001, the Commission approved a 0.8¢/kWh reduction in the stranded cost component of delivery rates for CMP's medium and large customers to mitigate the impact of significantly increased market generation prices. In 2002, the Commission approved a modest extension of the rate mitigation for CMP's and BHE's large industrial customers (0.45¢/kWH and 0.4¢/kWh respectively), and in February 2003, the Commission approved a 0.3¢/kWh mitigation for CMP's medium and large customers through February 2005. These rate mitigation activities exhausted CMP's and BHE's Asset Sale Gain Accounts.

V. OVERALL CONSUMER PRICES

Many consumers in Maine pay a lower overall price for their electricity now than they did before restructuring. This is especially notable in CMP's territory, where distribution and stranded cost rates have decreased steadily since CMP sold its generating assets in 1999.[11] Rate changes since 1999 are attributable to many factors other than restructuring, including such diverse factors as natural gas prices, utility cost containment efforts, and FERC cost-allocation decisions. Furthermore, the prices for C&I customers in particular vary considerably based on their operating characteristics and their supply contract terms. Nonetheless, a comparison of average electricity prices in 1999 and 2003 is shown in the tables below.

Average Residential Rates

	1999	12/2003
CMP	13.2	11.9 ¢/kWh
BHE	14.5	14.8
MPS	12.8	13.2

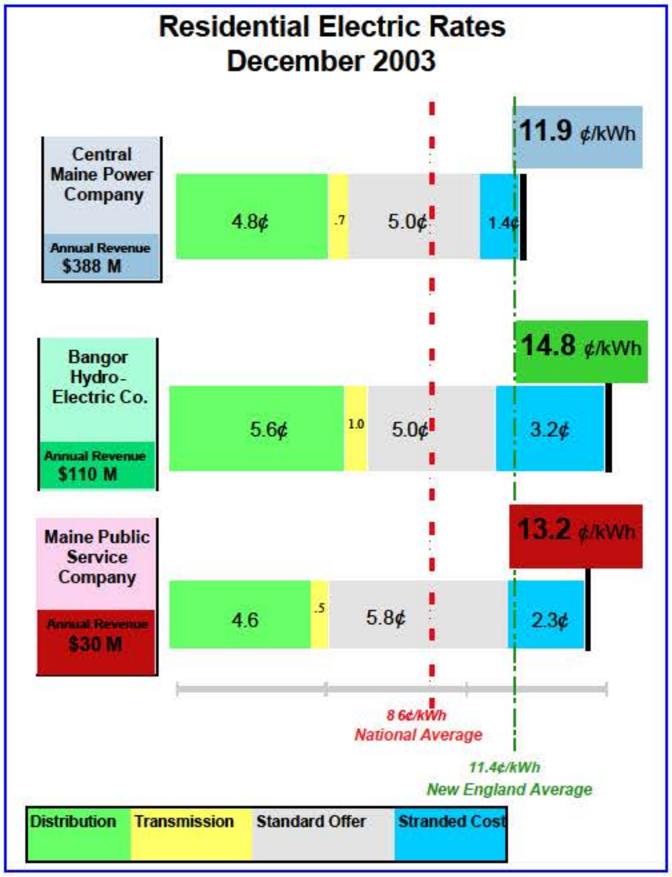
Average Large Industrial Rates For Customers on Standard Offer[12]

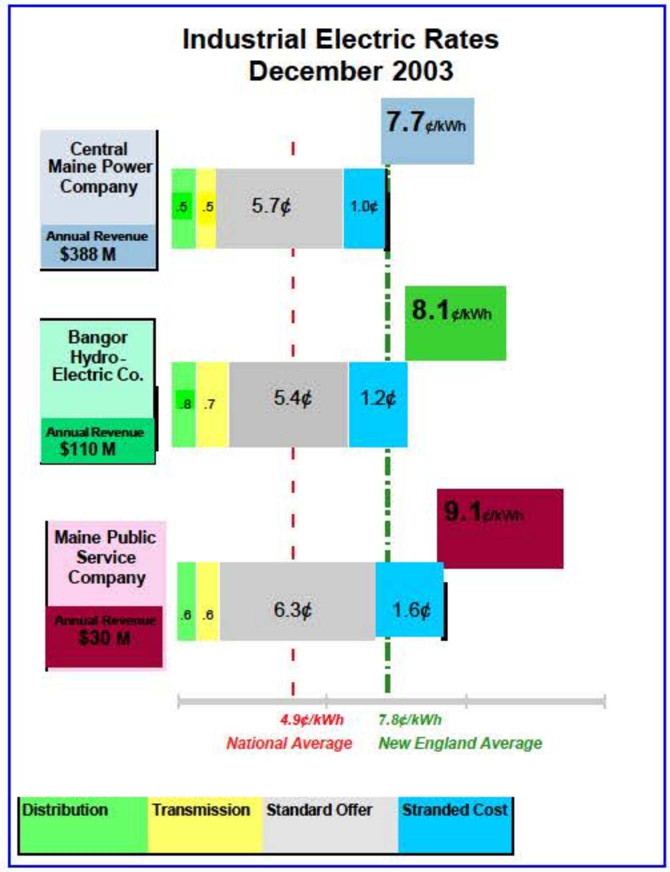
	1999	12/2003
CMP	7.2	7.7 ¢/kWh
BHE	9.7	8.1
MPS	8.4	9.1

T&D rate changes may occur in one of three T&D rate components. Distribution rates may change to reflect the utility's costs of delivering power and maintaining customer service. Transmission rates are determined annually by the Federal Energy Regulatory Commission (FERC), and reflect the cost of maintaining transmission facilities used to transport power throughout the region. Finally, stranded cost rate components change as utilities' generation contracts expire and market conditions change. In addition, generation supply prices – both standard offer and open market – fluctuate over time and may vary considerably from supplier to supplier.

[11] CMP's T&D residential rate decreased 27% between February 2000 and July 2003.
[12] The table assumes standard offer prices for generation. Customers receiving generation from the open market will have lower or, in some cases, higher generation rates than standard offer customers. In addition, industrial T&D rates vary significantly. Rates for customers receiving transmission-level service are less than those receiving distribution-level service and rates for customers on special rate contracts are less than those on tariffed rates.

The following charts display the current components of residential and large industrial prices in BHE, CMP, and MPS territories. The charts show that stranded costs still comprise a significant portion of customers' rates, while transmission rates have a negligible impact on total rates.



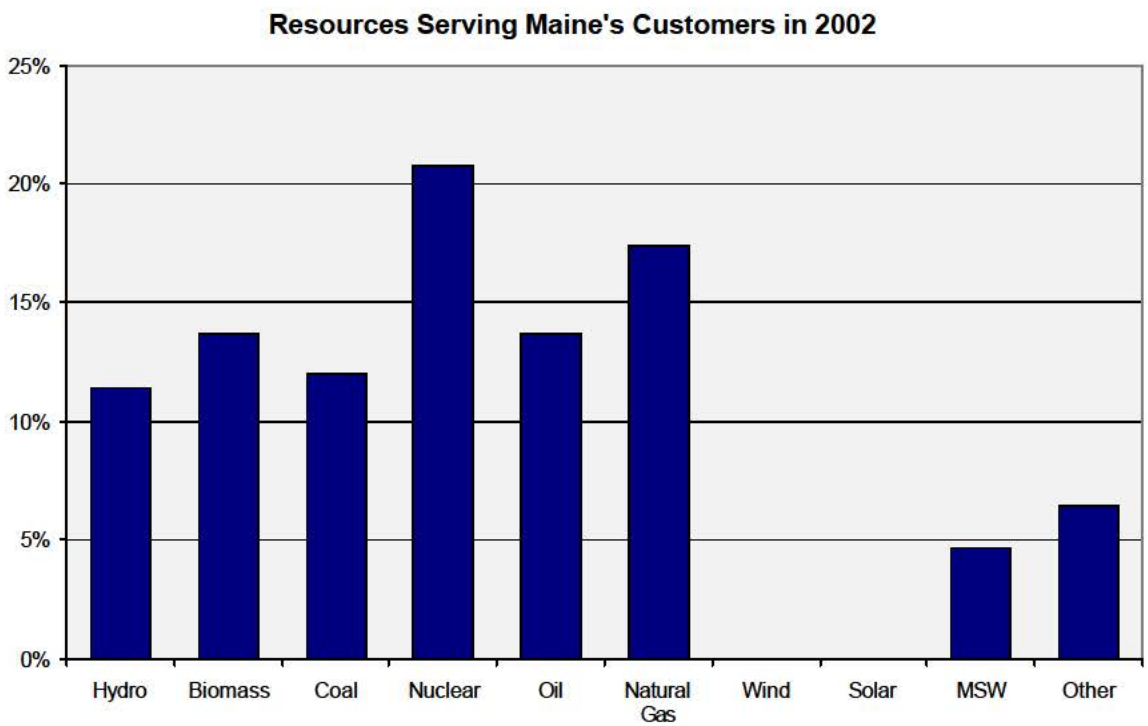


VI. GENERATION RESOURCES

Resource Mix

The Restructuring Act establishes a "30% Resource Portfolio Standard (RPS)," that requires electricity suppliers (including standard offer suppliers) to supply 30% of their Maine load from "eligible resources." The Act defines eligible resources to be generating units whose capacity does not exceed 100 megawatts and that produce electricity from tidal, fuel cells, solar, wind, geothermal, hydroelectric, biomass, and municipal solid waste in conjunction with recycling, that qualify as small power producers under Federal regulations, or that are efficient cogeneration units.

During 2002,[13] approximately 38% of Maine's load was supplied by eligible resources. Approximately 30% was supplied by resources designated as renewable in the Restructuring Act (hydroelectric, biomass, municipal solid waste, wind, and solar). Overall, suppliers used system power, which is power purchased from the New England or Maritimes control area through daily bids, to supply over 45% of Maine's load requirements. A portion of the system power was used to comply with Maine's 30% requirement, while the majority (over 80%) of the RPS was met through dedicated contracts. The following chart displays the resources serving customers in 2002. Appendix B contains additional information.



During 2002, NEPOOL implemented a "tradable attribute" certificate system known as the Generation Information System (GIS). The GIS allows for the trading of electricity attributes (e.g., fuel source and emissions levels) separate from the energy commodity. During 2003, the Commission revised its rules to require that suppliers demonstrate compliance with Maine's 30% RPS through GIS certificates. This change reduces supplier compliance costs and simplifies Commission verification.

[13] The Commission will receive information about suppliers' 2003 resource mix when suppliers file their annual reports in May 2004.

A dispute continues between some qualifying facilities and utilities over which entity retains the rights to GIS certificates associated with ongoing power purchase contracts. During 2002, the Commission investigated the issue and tentatively concluded that the utilities retain the rights to the certificates and that the certificates therefore should be transferred to the entitlement purchaser. During 2003, the matter was considered by FERC. A final decision is pending.

Re-evaluation of Maine's 30% RPS

In its 2003 session, the Legislature directed the Commission to investigate the effectiveness of Maine's 30% RPS in encouraging generation from renewable and indigenous resources. The Commission's findings and recommendations will be reported on December 31, 2003.[14] In its draft report, the Commission determined that the current RPS does not result in additional renewable or indigenous generation but nonetheless may increase generation costs to Maine's electric consumers. The report will summarize barriers and costs associated with specific renewable fuels, estimate the cost of various incentive mechanisms, and outline potential improvements to the current RPS structure.

Uniform Disclosure Labels

The Restructuring Act directs the Commission to ensure that comparative information regarding electricity supply is disseminated to customers. The Commission implemented this directive by designing a uniform information disclosure label that contains a supplier's resource mix and emission information. Residential and small commercial customer suppliers must provide a disclosure label to their customers quarterly, and suppliers to larger customers must provide the label annually. Labels for standard offer providers may be found on the Commission's web page. A representative label is contained in Appendix C.

During 2003, the Commission continued to improve the clarity of the uniform disclosure label. In addition, the Commission revised its rules and removed comparative price information from the labels to avoid the confusion and potential misinformation that may be conveyed if a supplier's price varies over time.

Voluntary Renewable R&D Fund

The Restructuring Act directs the Commission to establish a program to allow electricity customers to make voluntary contributions to fund renewable resource research, development, and demonstration projects. To date, customers have donated in excess of $100,000 through direct contributions or monthly contributions through their electricity bills. The State Planning Office, which administers the program, has contracted with the Maine Technology

[14] The Renewables Report will be available on the Commission's web page, www.state.me.us/mpuc under the Legislative Activities icon.

Institute (MTI) for distribution of the funds to take advantage of MTI's existing grant process infrastructure and to leverage other grant funds. In December 2003, MTI approved funding for a Chewonki Foundation and Hydrogen Energy Center project to develop an energy system using hydrogen generators, storage, and fuel cells. The project would be funded through a variety of sources, including $40,000 from the Voluntary Renewable R&D Fund.

VII. REGIONAL ACTIVITY

With the restructuring of the electricity market over the past several years, Maine has become part of a broader regional market for wholesale electricity. The existing electric transmission system allows generation within roughly 1,000 miles of the state to compete to serve Maine customers and allows our generators to compete for load over a similar area. The Legislature anticipated this and in 1997 enacted 35-A MRSA §3215, which authorizes the Commission to participate in regional and national activities to protect "the interests of competition, consumers of electricity, or economic development of the state."

The New England electric market is, and will remain for the foreseeable future, a hybrid of competitive and regulated elements. The fundamental goal is to develop and maintain a workably competitive wholesale generation market that will provide the benefits of strong competition among suppliers while simultaneously producing a reliable electric system and acceptable prices.

The market operates under a set of rules approved by the Federal Energy Regulatory Commission (FERC). New England's Independent System Operator, ISO New England (ISO-NE), is the day-to-day operator of the electric grid and the generation markets. ISO-NE, in turn, operates under contract with the New England Power Pool (NEPOOL), a New England organization comprised of generators, electricity suppliers, T&D utilities, municipal electric systems, and representatives of end-use customers. NEPOOL or ISO-NE files changes to market rules for approval by FERC. These changes are developed through NEPOOL committees, each of which is chaired by ISO-NE. In some cases, these filings have close to unanimous support. In others, there is a wide range of conflicting positions. While the Commission is not a NEPOOL member, it often takes an active role in the committees. The Commission also intervenes and takes positions at FERC on matters affecting (1) the competitiveness of the wholesale electric markets, (2) reliability, and (3) prices paid by Maine electricity consumers.

This section of the report outlines the changes in the market over the past years and describes the Commission's regional and national activities.

Notable Changes in the Past Year

1. Standard Market Design. On March 1, 2003, ISO-NE switched to a new "Standard Market Design" (SMD) for the electric energy market in New England. (The energy market is the largest and most important market.) There are two major changes under this new approach. First, the energy market now comprises two separate markets. In the Day Ahead market, which covers energy transactions for the following day, buyers and sellers can, but are not obliged to, lock in financial positions. Then, in the real time market, any deviations between the Day Ahead market and the actual outcomes are cleared. This allows market participants to hedge against unexpected events such as extreme weather or the unexpected loss of supply resources, either of which can drive prices very high very quickly[15].

The second change has particular importance to Maine consumers. Under SMD, customers in different regions in New England pay different prices. This happens for two independent, if related, reasons. First, SMD recognizes "transmission constraints." This means that, if there is more low cost generation in a region than can physically be exported, the energy price in that region will decline to reflect the surplus supply, while prices in the transmission import constrained or "congested" area are likely to increase to reflect the limited generation supply. Second, SMD changes the way transmission losses are charged[16]. Under SMD, marginal line losses are charged to customers. In exporting regions such as Maine, the "losses" can be negative, meaning that the effect of losses is to reduce the price paid for electricity.

The new SMD energy market became operational on March 1, 2003. Between April and October 2003, the average wholesale price of electric generation in Maine was $41.89 per MWh while the average New England Hub price (an index of typical New England prices) was $46.27, roughly $4.40 higher. Maine's advantage comes from lower losses (which explain about 75% of the difference) and lower congestion costs (accounting for the other 25%). Connecticut, the highest cost state in New England, paid average wholesale prices of $47.95 or over $6.00 over Maine.

Savings of this magnitude are significant for Maine. For example, if Maine's prices run, on average, $4.00 per MWH below those of New England as a whole, Maine saves roughly $40 million per year. The table below shows the monthly prices for Maine, the New England Hub, and Connecticut during this period. We cannot be certain that this price advantage will continue. However, it appears likely that such differences will remain, at least for the next few years.

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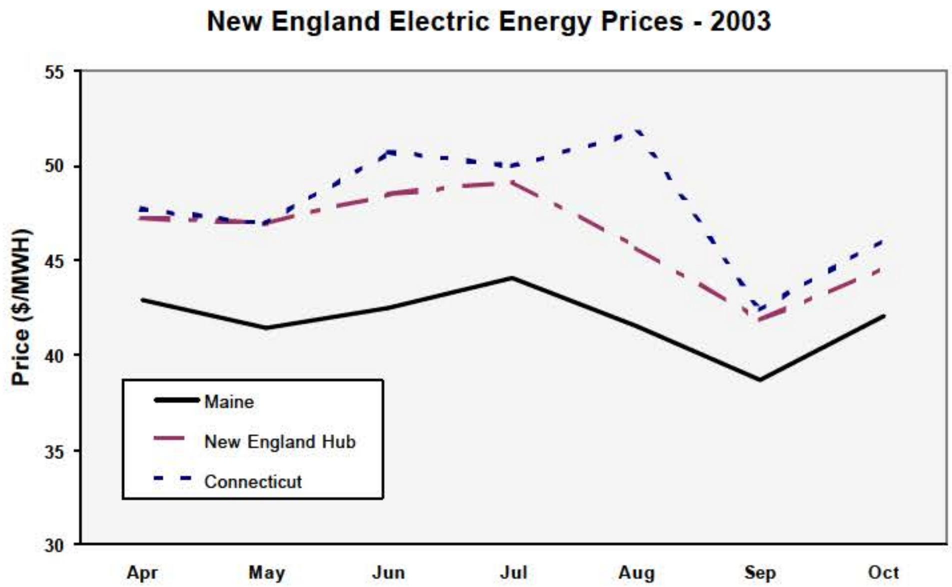
[15] Before SMD, the market was a simple real-time market and left market participants vulnerable to unexpected events.

[16] Any time electricity is transported, a portion of the electricity is lost. The loss percentages can range from less than 1% to 10% or more, depending primarily on the amount of current flowing over the line.



2. Financial Issues for Generators. A number of firms owning generation have experienced serious financial problems, some of them resulting in bankruptcy filings. This has at least two implications: it suggests that market prices have been low, relative to these firms' expectations when they entered the market; and it indicates that the risk of financing new generation will affect New England's portfolio of generation resources which in turn will affect the composition of the wholesale electric markets.

3. ISO-NE's Independence. ISO-NE has asserted its independent role to a greater degree during the past year. The ISO's increasing independence has been strongly supported by the Commission individually and as part of the New England Conference of Public Utility Commissioners (NECPUC). Regulator support of greater ISO independence offsets the inherent incentive for market participants to support their own self-interest in issues before the ISO.

4. RSC Formation. The FERC has increasingly articulated the need to have problems such as regional reliability issues addressed by entities closer to the problem. The FERC has thus encouraged the formation of Regional State Committees (RSCs) to address reliability and other matters. In New England, it is likely that an RSC will be proposed to the FERC in December 2003. The RSC is designed at this time primarily to address matters concerning generation adequacy[17] and transmission planning. The Commission, through Chairman

[17] For a description of our work in this area, see "A proposal for the structure of a capacity market for a competitive wholesale electricity market: Advance funding for the right and obligation to

Welch, has been active in developing the RSC. In November, Governor Baldacci appointed Kurt Adams as Maine's representative to the new RSC.

5. RTO Formation. ISO-NE decided to restructure into a Regional Transmission Organization (RTO) consistent with direction provided by the FERC. ISO-NE currently operates under an Interim Agreement with NEPOOL. This agreement has been extended several times, most recently until December 31, 2004. The ISO has indicated that the organization has had more difficulty focusing on long-term objectives because its existence has been periodically threatened as the contract approaches its expiration date. The ISO views one purpose of RTO formation as giving the ISO the stability needed to ensure that it can function independently.

Another reason for the ISO's interest in RTO formation is to codify the ISO's operational authority over the transmission facilities of the transmission owning utilities. While the Restated NEPOOL agreement provides for ISO operational authority over such facilities, many specific aspects of this operational authority are not set forth in that document. A third reason for RTO formation is to solidify the ISO's authority to propose changes to the market rules to FERC rather than sharing this authority with NEPOOL.

On October 31, 2003, the Transmission Owners and ISO-NE jointly filed a petition at FERC to form an RTO. The Maine Commission and NECPUC have filed comments at the FERC, seeking to have the FERC condition its approval upon certain changes being made to the RTO proposal. The changes proposed by the Commission would, in our view, strengthen the independence of the RTO while ensuring an appropriate level of openness and responsiveness to concerns raised by those affected by the RTO's actions.

6. Transmission Cost Allocation

The Commission led a coalition of state regulators and public advocates in Maine and Rhode Island, CMP, and a number of suppliers in proposing a revision to the regional method for allocating the cost of transmission upgrades. The current system rolls into the regional transmission rate the costs of all transmission upgrades above a certain kV level. Because of excess generating capacity in the State, Maine will not benefit from most of the upgrades in New England. While FERC has recently issued an order that continues NEPOOL's current socialization policy, the Commission continues to advocate for a result that is consistent with locational marginal pricing and with the interests of Maine's ratepayers.

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provide capacity" by Tom Welch and "The Maine Proposal for Capacity Adequacy – The 10,000-Foot View" by Tom Welch and Tom Austin. Both are available at http://www.state.me.us/mpuc/.

VIII. AFFILIATED COMPETITIVE PROVIDERS AND COMPLIANCE COSTS

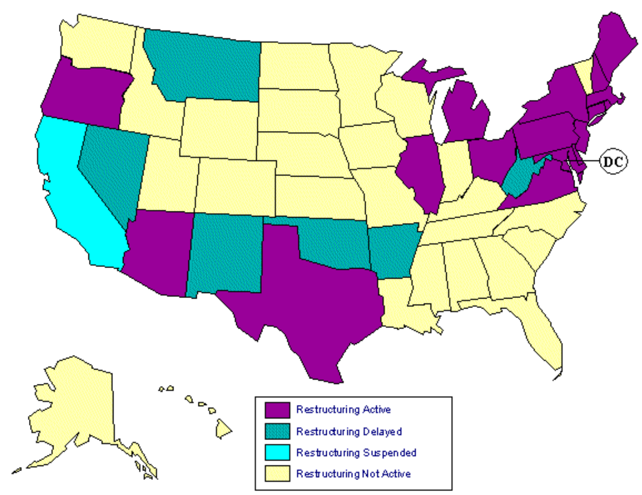
The Restructuring Act requires T&D utilities and their marketing affiliates to comply with comprehensive standards of conduct and market share limitations. These limitations are intended to prevent utility marketing affiliates from obtaining any undue market advantage by virtue of their corporate relationship with T&D utilities. The Act requires the Commission to determine and report the actual and estimated future costs of implementing these requirements.

During 2003, issues associated with standards of conduct were minimal. CMP does not have a marketing affiliate. BHE formed a marketing affiliate, Emera Energy Services, Inc. (EES), but EES does not market services in BHE's territory. Finally, during 2003, MPS's marketing affiliate, Energy Atlantic, announced its intention to withdraw from future marketing in MPS's territory.

The Commission's costs of implementing the affiliate marketing requirements continue to be modest, comprising the use of internal resources to act on BHE's request to form its marketing affiliate[18] and to consider a request by EA for a waiver of the terms of an agreement associated with EA's interaction with MPS.[19] The Commission, BHE, and MPS foresee that their costs will continue to be moderate in the future.

IX. ACTIVITIES IN OTHER STATES

The Restructuring Act directs the Commission to report on activities relating to changes in the regulation of electric utilities in other states. During 2003, there was no significant activity regarding implementation of competition. As shown in the map to the right,[20] 17 states and the District of Columbia allow retail competition for electricity supply. Of the remaining states, 26 are not currently carrying out restructuring activity, six have studied but are delaying restructuring, and California has suspended restructuring.



[18] The Commission approved the formation EES during 2002, and the Public Advocate and Competitive Energy Services appealed the decision to the Law Court. The appeal was denied in January 2003.

[19] When EA withdrew from the northern Maine market during 2003, it petitioned the Commission for a waiver of the requirements of Chapter 304 (Standards of Conduct for Transmission and Distribution Utilities and Affiliated Competitive Electricity Providers) of the Commission's rules and of certain terms reached during a 2002 dispute regarding its affiliate interactions with MPS. The matter was resolved by stipulation, which was approved by the Commission.

[20] Source: Energy Information Administration. West Virginia is no longer active.

Appendix A
Commission's Activities to Lower Barriers to Electric Sales between The United States and Canada

During the 2003 legislative session, the Legislature enacted P.L. 2003 ch. 5, Resolve, Regarding the Reduction of Barriers to the Transmission of Electricity, which directs the Commission to work with the government of New Brunswick to study ways to reduce costs and barriers to the flow of electricity between Maine and Atlantic Canada. Pursuant to the Resolve, this Appendix describes the Commission's activities conducted in response to the Resolve.

I. Summary

During 2003, the Commission continued to work with representatives of the government of New Brunswick and market participants to identify, and find ways to resolve, constraints on the electricity trade between New Brunswick and Maine. This activity builds upon work already done by the Commission (in particular, a formal investigation of generation adequacy in northern Maine, heightened monitoring of the number of competitive providers available in various regions of Maine, and a report submitted to the Legislature on February 28, 2003 addressing in general the issues in northern Maine[21]). The activities this year do not involve any sharp departure from our prior efforts or analyses, but rather have been attempts to move towards solutions that are viewed, by the majority of market participants, as appropriate steps toward a more fully integrated market.

The Commission examined two distinct but interrelated markets: the first is the market in northern Maine that is physically a part of the Maritimes Control Area, and thus interconnected to the rest of Maine (and New England) only through transmission lines to and through New Brunswick. The second is the market for electricity between New Brunswick and Maine through the MEPCO transmission line, which extends (in theory) to trade with the entire NE-ISO market .

There are two issues involving New Brunswick relating to the northern Maine market (served by MPS, Van Buren, Eastern Maine Electric Cooperative, and Houlton Water Company). The first is whether there are sufficient sellers of electric energy willing and able to serve the northern Maine market to ensure a competitive price. Our concern here is driven in part by the very small number of suppliers who have chosen to participate in the northern Maine retail market. The second is whether the physical interconnections with New Brunswick are sufficient to provide northern Maine with the energy needed to provide system reliability.

[21] The report may be found at http://www.state.me.us/mpuc/2002legislation/2002-2003Legislative%20Reports.htm under the "Maine/Canadian Regional Transmission Organization Report" icon.

On the first issue, it appears that, for a variety of reasons, New Brunswick Power (NBP) possesses, but does not exercise, a high degree of market power. For this reason, the Commission is working with the market participants and the government of New Brunswick to see what further steps should be explored to ensure that electric energy prices in northern Maine remain at acceptable levels. Possibilities include a reduction in the "through and out" transmission charges now paid to NBP by sellers in New England seeking to reach the northern Maine market, the preservation of "back-up service" now available to address the lack of firm south to north transactions on the MEPCO line, and the addition of capacity in the transmission link between the NE-ISO area and New Brunswick through, for example, a second tie line. The Commission expects proposals for adding additional generation capacity to northern Maine to be made in the near future, some of which may depend upon some modification to the current rules relating to restructuring, in particular with respect to the role of MPS and other T&D companies serving northern Maine.

With respect to trading between New Brunswick and New England, including "southern" Maine, the primary issue is whether there are transmission capacity or tariff impediments to the free flow of energy. While at the moment New Brunswick has surplus energy capacity, and flows from north to south (i.e. from New Brunswick to southern Maine) are much more easily arranged than flows from south to north, both these circumstances may change[22] in ways that would provide a greater degree of "two-way" trading. When New Brunswick's capacity margins shrink, for example, there may be a market available to generators in Maine (and elsewhere in New England) in which to sell their output. The ability to reach that market, however, is currently constrained by the limitations on "firm" south to north flows on the existing MEPCO line. Thus there is renewed interest in developing additional south to north capacity, either through improvements to the existing MEPCO line or by building a second transmission line.

II. PUC Activities and Market Participants' Concerns

During 2003, the Commission continued to solicit the views of all participants in the Maine, Canada and New England electricity markets to help inform our views of what could, and should, be done to ensure that all consumers in Maine gain the greatest possible benefit from the broader electricity markets. In particular, the Commission sent a letter to interested persons (including all relevant market participants and government agencies) asking for comment on "the existence of specific institutional or structural barriers, and any unnecessary or burdensome transaction costs associated with the flow of electricity from and between (northern) Maine and Atlantic Canada." The Commission received

[22] There is uncertainty concerning how long the Point Lepreau nuclear generation unit will continue to operate. If the unit goes out of service for an extended period of time, it becomes more likely that the current surplus capacity situation in New Brunswick will reverse, and New Brunswick could become a net importer of electric energy.

written comment from the northern Maine Independent System Administrator; Emera Inc.; Boundless Energy, LLC; ISO New England; Maine Public Service; Energie NB Power; Houlton Water Company; and Central Maine Power. The Commission also hosted a meeting to discuss these and related issues in Houlton on September 17, 2003. The meeting was attended by representatives of all of those who had filed written comments, and also by representatives of Bangor Hydro Electric Co.; the Office of Public Advocate; Energy Supply; WPS Energy Services, Inc.; Duke Energy North America; Van Buren Light & Power District; Loring Bio-Energy; New Brunswick Public Utilities Board; and Eastern Maine Electric Coop.

While the comments and discussions raised a wide variety of issues concerning the markets and offered an equally wide array of possible solutions, a few themes emerged as the primary subjects for discussion and further action. These were the effects of the separate MEPCO tariff on transactions between New England and both northern Maine and New Brunswick; the prospects for and possible benefits of a second major transmission line between New Brunswick and the NE-ISO system; the extent to which transmission rate "pancaking" diminishes the competitive supply available to northern Maine; and the extent to which localized solutions (including additional generation and local transmission) may be required for market and reliability purposes in the northern Maine market.

The Impact of the MEPCO Tariff

Some market participants suggested that the current MEPCO tariff and scheduling practices impede trade between New Brunswick and New England, and further reduce the opportunities for trade between New England and northern Maine. In particular, some objected to the need for energy suppliers to obtain reservations on the MEPCO line, and pay an additional tariff beyond the New England Regional Network Service rate. Some parties suggested that it would be advantageous to the market if the MEPCO line were "rolled into" the NE-ISO regional tariff.

The MEPCO owners raised two objections to "rolling in" the MEPCO line. First, the MEPCO owners have sold firm transmission rights on the lines; thus any attempt to bring the MEPCO line under NE-ISO operational control would require some financial accommodation to those who have already paid for long-term rights to the transmission capacity. Second, the NE-ISO regional transmission tariff is reset annually by the FERC based on current costs, while the MEPCO line charges generators a fixed rate for transmission over the line. Because the MEPCO line is largely depreciated, the MEPCO tariff provides revenues above current costs. Shifting MEPCO line rates to the NE-ISO tariff would therefore result in a loss of profit to the MEPCO owners.

While the parties agreed that the issue is still worthy of study, our assessment is that the current MEPCO tariff structure is not a major barrier to trade. For one thing, the rate is relatively low, adding about $1.96 to each kW-year plus $0.47 per MW-hour (on-peak) traded from Orrington to the New Brunswick border, and about $3.51 per kW-year plus $0.84 per MW-hour (on-peak) from Maine Yankee to the border. It also appears that the MEPCO owners are working with the NE-ISO toward a satisfactory resolution of the scheduling issues. Moreover, there are legal impediments that would make it difficult to compel the MEPCO owners to relinquish control over the line, or revise how the line is tariffed.

For these reasons, the Commission does not view changes to the current MEPCO structure and tariff to be a high priority. Should the market demonstrate otherwise, however, it may be appropriate to petition the FERC to require changes (for example, by bringing rates more in line with current costs).

The Second Tie Line

Virtually all parties agreed that building a second tie line from New Brunswick to the NE-ISO system would help, to some degree, both the northern Maine market and the broader Maine/New Brunswick market. First, a second line would substantially increase the ability to schedule, on a firm basis, transactions from the New England system to New Brunswick (i.e. south to north) and thus into northern Maine through New Brunswick. Second, because New Brunswick's current surplus of capacity is likely to disappear in a few years (at least temporarily), a second line would allow New Brunswick to import the power it needs with less upward pressure on its wholesale prices. It is worth noting, however, that increasing the flow of energy from Maine into New Brunswick may have the effect, to the extent that the existing transmission constraint between Maine and the rest of New England is not relieved, of diminishing Maine's current advantageous price position relative to New England.

Subject to ensuring that Maine customers -- both in northern Maine and in NE-ISO areas -- receive benefits from the second line, the Commission’s view is that building a second line would be a positive development.[23] The New Brunswick and New England systems are meteorologically diverse (New Brunswick peaks in winter, New England in summer), so greater trade between the systems is likely to produce generation efficiencies. Moreover, until the existing transmission constraint between Maine and the rest of New England is removed, increasing south to north flows provides some opportunity for generators in southern Maine to find additional buyers.

[23] At least one party suggested that there may be other ways of providing additional "firm" south to north capacity, for example by making certain modifications to the existing facilities. While difficult to evaluate in the abstract, we are indifferent to the technology used. It may be, moreover, that the additional capacity in both directions that a new tie would bring would be sufficient to justify the new line regardless of whether modifications are made to the existing line.

Notwithstanding these potential benefits, however, the Commission's view is that it would be appropriate to insist, as a condition of allowing the second tie to be built, upon commitments that customers in northern Maine see a benefit. For example, it might require that, even in periods of generation capacity shortages in New Brunswick, New Brunswick allow an amount of energy to flow through the New Brunswick transmission system sufficient to ensure reliability and the opportunity for price competition in northern Maine. Similarly, it might be reasonable to require that the tariff charges imposed by New Brunswick (and the owners of the new line, if that line is not "rolled into" the NE-ISO regional tariff) on energy flowing from New England to northern Maine be sufficiently low to avoid discouraging sales from Maine and elsewhere in New England into northern Maine, thus providing some price discipline to the northern Maine market.

The Commission has also committed to working closely with the Maine DEP and other relevant state and federal agencies to ensure that the process for obtaining permits for the second line (or other projects designed to improve market conditions and reliability) is efficient and "user friendly" without sacrificing the ability to consider legitimate input from those affected by the proposals.[24]

Transmission Rate Pancaking

In order to deliver energy into northern Maine from New England (including "southern" Maine), a supplier (or its customer) must pay at least four transmission tariffs: the rate within New England ("RNS"), the MEPCO rate, the "through" New Brunswick rate, and a rate for the local system in northern Maine. While none of these may be prohibitive in itself, the accumulation of rates, and the need to deal separately with each system, clearly discourage trade. Since the northern Maine market is so small, it is not surprising that, since Maine opened its market, no trades have been accomplished over this multi-tariff path.

In addition to the initiatives discussed above with respect to MEPCO and possible conditions that might be placed on a second tie line, parties are currently engaged in both bilateral and multi-party discussions with the goal of reducing or eliminating the pancaking of transmission rates. One idea that is now being considered (and studied further) is whether it might be possible to incorporate northern Maine into the New England tariff. If the second tie line were built, sellers in New England would be able to reach northern Maine by paying only the regional tariff plus any "through" New Brunswick charge.

The Commission will continue to work with the various parties to encourage the elimination or reduction of rate pancaking.

[24] Because it is likely that issues relating to the second tie line will come to the Ccommission for adjudication, any comments here concerning the desirability of the line must be viewed as tentative, and do not in any way indicate any view on whether the legal standards for approval have or can be met.

Localized Solutions

In addition to the prospect of facilitating trade between northern Maine and New England (through New Brunswick), several parties indicated that increasing the generation within the northern Maine area itself, and increasing the strength of the transmission links between northern Maine and New Brunswick, should also be considered as part of the "solution" to the market and system isolation of northern Maine.

It appears that MPS and NBP are addressing the most immediate local transmission issues, relating to the reliability of the existing links between their systems. In fact, one important upgrade has already been completed in MPS territory, and the MPS Board has approved another (which is currently being negotiated with NBP).[25] We also understand that there are discussions between and among the parties to determine what further strengthening of the links may be cost-effective.

At least two generation projects[26] are under active consideration within northern Maine. While they differ significantly in their characteristics, and in the variety of approvals they would need, either or both would, to some extent, enhance both the system reliability and market competitiveness of the area. For that reason, we have encouraged both projects to move forward, and have, as with the second tie line project, committed to working with our sister state agencies to ensure a fair and prompt review. From a purely economic perspective, additional generation geographically located within northern Maine may be indistinguishable from electric energy brought in from New Brunswick or New England. There may be, however, some reliability benefits to be gained by having additional local generation, and of course there may be some economic development benefits to the construction and operation of any new resources.

The Commission has asked the parties to consider whether some form of "capacity market," perhaps using a single buyer (who might be the NMISA or even one of the T&D companies), should be introduced in northern Maine to help provide financing for new generation projects. These discussions are continuing, and are likely to be informed by similar discussions now taking place among the states in the northeastern United States and at the FERC.

III. PUC activities and next steps

In light of the new standard offer for MPS, most customers in northern Maine are largely protected from market failures through December of 2006.

[25] Again, the Commission's view of the need for a second tie line to serve New Brunswick may be influenced by the successful completion of projects needed to bring the benefits of any such project into northern Maine.

[26] The Commission is aware of a project for grid-scale wind in Mars Hill, and a gas-fired generator at Loring.

This provides, in our view, a degree of "breathing space" to enable the Commission and the parties to work through the options described above. It may not be coincidental that at least some of the projects (e.g. the tie line and some of the generation projects) are targeted to come on line roughly during that period which also coincides with the termination of the supply contract with Wheelabrator-Sherman. The Commission approach in the near term, therefore, is to continue to meet with the relevant parties (including through annual or even more frequent meetings in northern Maine or New Brunswick) to review their progress, while ensuring that the regulatory processes that may be necessary to bring helpful projects to fruition are conducted expeditiously. We expect, in the near future, filings relating both to generation projects in northern Maine and the second tie line (and/or upgrades to the existing MEPCO line). The Commission will also monitor developments within New Brunswick (in particular the moves within New Brunswick to redesign its market structure) to determine the impacts that such developments may have on Maine's electricity markets, and to ensure to the extent possible that activities on both sides of the border are complementary.

Finally, as discussed earlier in this report, the Commission continues to monitor whether significant changes are required in the rules governing the northern Maine market to address the possibility that the restructuring model in place elsewhere in Maine is unlikely to produce the same benefits due to the geographic isolation and size of the market. While the recent standard offer contract for northern Maine suggests that, at least for the next three years, northern Maine consumers are not at a pronounced disadvantage relative to their southern neighbors, we are reviewing whether we should take additional steps to ensure that a reliable, and competitively priced, supply of electric energy remains available for the long term for those customers.

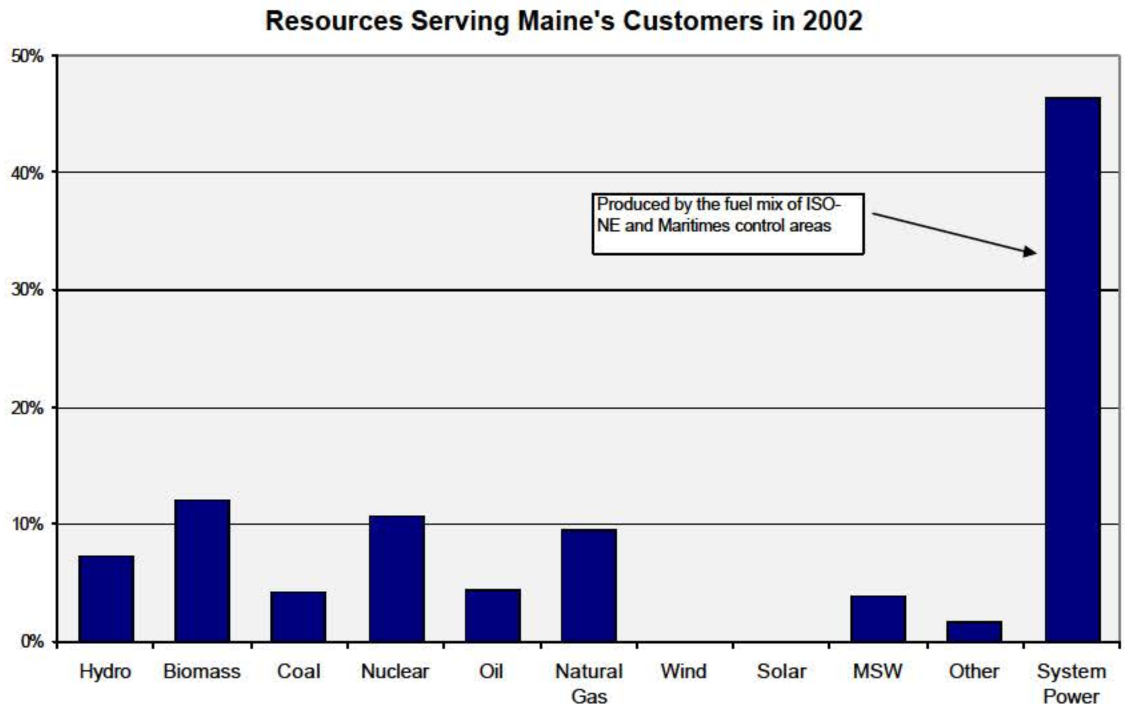
IV. Proposed legislation

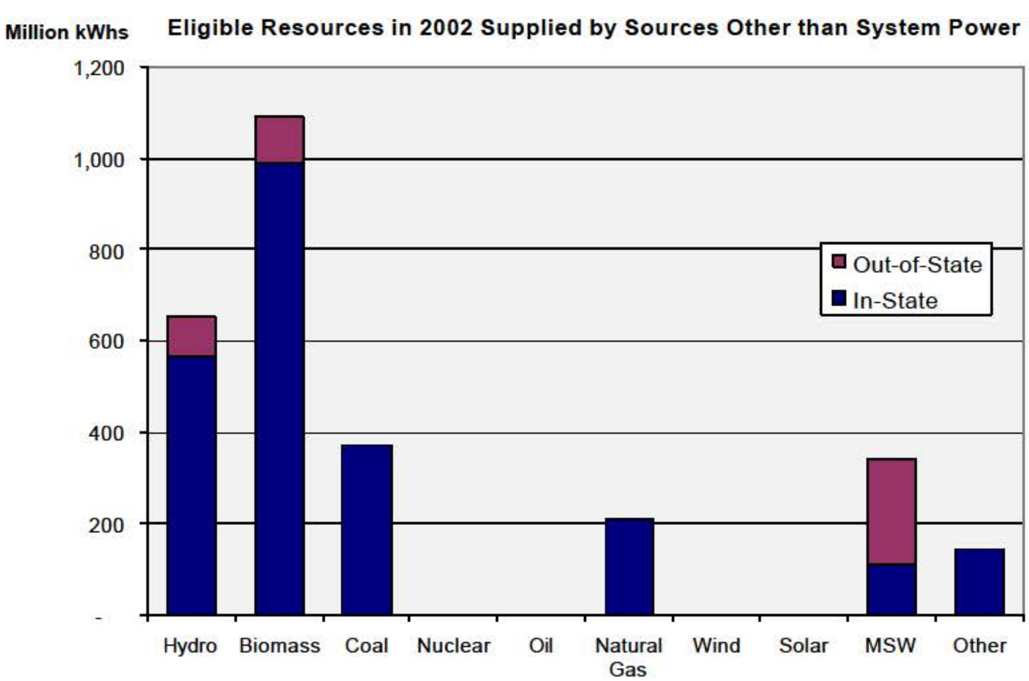
We do not recommend, in the near term, any new legislation to address the northern Maine market or the relationship between Maine and the Maritimes provinces.

In part because no single solution has emerged as clearly preferred, in part because at least some of the proposals require no changes to existing law, and in part because the new standard offer provides a degree of price stability for most northern Maine customers, legislative intervention would be premature. There is reason to believe, however, that within the next twelve months the picture will become clearer, and should legislation prove necessary to accomplish the reliability and market objectives shared by the Legislature, the Commission and the market participants, the Commission will bring forward appropriate legislation in time for consideration in the next session.

Appendix B
Resources Serving Maine's Customers in 2002

In addition to the graph in section VI, the following graphs provide information about the source of resources that served Maine's customers' loads during 2002. The first graph displays the percentage of generation obtained through purchases of system power, as compared with dedicated contracts. The second graph displays the portion of dedicated contracts that purchased power from facilities outside of Maine.





Appendix C
Uniform Disclosure Label

During 2003, the Commission worked with suppliers and utilities to improve the clarity of the uniform disclosure label. The following format is used for all standard offer labels.

RESIDENTIAL AND SMALL NON RESIDENTIAL STANDARD OFFER SERVICE
CONSUMER INFORMATION ABOUT YOUR ELECTRICITY SUPPLY

November 2003

Electricity suppliers in Maine must, by Maine law, provide fact sheets, or "uniform disclosure labels" from time to time to educate consumers about their electricity service. Your electricity is *delivered by* Central Maine Power Company, but the *electricity itself* is supplied by:

Your Electricity Supplier is: Constellation Power Source Maine, LLC.

This fact sheet provides consumer information about the price, power sources and air emissions of service provided by this electricity supplier.

Power Sources

(October, 2002 – September, 2003)

This supplier provided electricity with the following resources:

	Supplier's Mix	New England Mix
Sources meeting Maine's 30% renewable and efficient resources requirement		
Biomass	8 5 %	5 2 %
Municipal Waste	5 6 %	
Fossil Fuel Cogeneration	7 4 %	NA
Fuel Cells	0 0%	0 0 %
Geothermal	0 0%	0 0 %
Hydro	11 3%	9 5 %
Solar	0 0%	0 0 %
Tidal	0 0%	0 0 %
Wind	0 0%	0 1%
Other Choices		
Nuclear	26 7 %	27 0 %
Gas	23 9 %	29 4 %
Oil	8 6 %	13 7 %
Coal	8 0 %	15 1 %
TOTAL	100 0%	100 0%

Air Emissions

(October, 2002 – September, 2003)

This table compares air emissions from this supplier's electricity mix to average emission levels from all New England power sources.

	Supplier's Mix (lbs/MWh)	
Carbon Dioxide (CO_2)	**774.6**	This is **0.7%** less than the New England Average
Nitrogen Oxide (NO_x)	**1.8**	This is **20%** more than the New England Average
Sulfur Dioxide (SO_2)	**2.6**	This is **33%** less than the New England Average

Notes: lbs/MWh = pounds per Megawatt-hour
1 Megawatt-hour = 1,000 kilowatt-hours

Additional Information and Required Notes:

Notes:

Power Sources—Maine law requires retail electricity providers to supply no less than 30% of their total annual kilowatt-hour sales with electric energy generated from eligible resources Either a renewable fuel or an efficient process, such as co-generation, must be used to generate the electricity used to satisfy this requirement Co-generation sometimes uses fossil fuels, such as gas, coal or oil, and is considered to be efficient because the process yields both electricity and thermal energy **Emissions**—Carbon Dioxide (COs) is released when certain fuels are burned It is considered a greenhouse gas and a major contributor to global warming ~~Nitrogen Oxides~~ (NOx) form when certain fuels are burned at high temperatures They are considered contributors to acid rain and ground-level ozone (or smog) Sulfur Dioxide (SO2) is formed when fuels containing sulfur are burned Major health effects associated with SO2 include asthma, respiratory illness and aggravation of existing cardiovascular disease The production of electricity can produce other harmful emissions and have other environmental impacts Environmental impacts differ among individual power plants

If you have questions or need further explanation, please contact Constellation Power Source Maine, LLC toll-free at 1-888-808-3826 or the Maine Public Utilities Commission, toll-free, at 1-877-782-3228. Additional information can also be found at http:www.maine.gov/mpuc.