

**Maine
Public Utilities
Commission**

**Annual Report on
Electric Restructuring**

December 29, 2000

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Annual Report on Electric Restructuring

Report to the Utilities and Energy Committee On Actions Taken by the Commission Pursuant to 35-A M.R.S.A. § 3217¹

I. INTRODUCTION

During its 1997 session, the Legislature enacted comprehensive legislation to restructure Maine's electric utility industry (the Restructuring Act). P.L. 1997, ch. 316 (codified at 35-A M.R.S.A. §§ 3201-3217). 35-A M.R.S.A. § 3217(1) states in part:

1. **Annual restructuring report.** On December 31st of each calendar year, the commission shall submit to the joint standing committee of the Legislature having jurisdiction over utility matters a report describing the commission's activities in carrying out the requirements of this chapter and the activities relating to changes in the regulation of electric utilities in other states.

During 2000, the Public Utilities Commission (Commission) directed the implementation of electric industry restructuring for all Maine's customers on March 1, 2000. We significantly increased our participation in regional wholesale market and transmission activities, monitored standard offer service and revised prices and procedures, monitored the activities of open market competitors, and approved rates for the regulated transmission and distribution (T&D) utilities. Our primary focus has been to create a healthy competitive retail electricity marketplace in which consumers can exercise choice and receive electricity at the lowest possible rates. This report describes our activities.

II. RETAIL MARKET ACTIVITY – YEAR 1

Competitive Electricity Provider Licensing

By the beginning of 2000, we had approved all the requirements governing licensed competitive electricity providers, and stakeholder groups had developed standard form contracts between utilities and providers, electronic business transactions (EBT) procedures for exchanging data between utilities and providers, and a provider training and testing program.

During 2000, these procedures were carried out regularly, as providers entered Maine at the onset of retail competition. The Commission and the utilities have received positive comments from competitive providers for the

¹Copies of documents referred to in this report are available on request or on the Commission's web page (janus.state.me.us/mpuc).

efficiency and effectiveness of the procedures. We usually complete the licensing process in under 30 days. The monthly provider training program taught by the utilities and the Commission has received high marks from the 80 provider representatives who have attended. Finally, utilities have completed the EBT testing process with providers, which often takes months in other states, in as little as one week. The result of these activities has been an environment in which competitive providers can establish their Maine business operations quickly and easily.

As of early December 2000, 35 competitive providers were licensed to provide service in Maine. Of those, 16 are aggregators or brokers and 19 are marketers selling electricity directly to customers. Of the 19 marketers, 9 will serve only large or medium customers.² A list of all licensed providers is included as Appendix A.

Migration to the Open Market

As anticipated, migration to the open market began with the state’s largest customers. During the Spring, one aggregation group of medium and large customers began purchasing energy from a competitive provider, while other large customers obtained providers independently. Two additional aggregation groups recruited medium-sized business customers for eventual migration to the competitive market. One marketer offered green power to residential customers, but response was minimal. By the end of May 2000, migration to the competitive market followed the patterns shown in the following table:

Load Served by Competitive Providers, End of May 2000

	CMP	BHE	MPS
Residential & Small Commercial	<1%	<1%	2%
Medium Class	6%	2%	21%
Large Class	65%	46%	7%
Total	29%	20%	7%

Enrollment activity declined during summer months because of high wholesale prices. However, an additional residential aggregation group solicited customers for eventual purchase of green power and recruitment continued within existing aggregation groups. In the Fall, retail activity increased and a new aggregation group of medium customers began purchasing energy from the open market. Residential activity remained low.

²Customers are divided into groups for the purposes of standard offer service, consumer protections, and load profiling and settlement. Within this report, we refer to four groups. Residential customers are households. Small commercial customers are businesses with loads less than 20 kW (in CMP’s territory), 25 kW (in BHE’s territory) or 50 kW (in MPS’s and all COUs’ territories). Large customers are businesses with loads above 400 kW (in CMP’s territory) or 500 kW (in all other territories). Medium customers’ loads fall between the small and large customer load breakpoints.

In Northern Maine, migration occurred more quickly. A far higher number of residential customers in Maine Public Service Company's (MPS) territory has migrated to the competitive market – 1680 customers, or 8% of the residential load – than did elsewhere in the State, despite the fact that the standard offer price in MPS's territory is substantially below Bangor Hydro-Electric Company's (BHE). However, the single provider that actively offered service to residential customers was a locally-owned company; a second provider agreed to serve residential customers but did not appear to solicit actively. By December, the percentage of load served by the competitive market in all three rate classes was higher in MPS's territory than in BHE's or Central Maine Power Company's (CMP).

The following table shows migration to the competitive market as of the beginning of December:

Load Served by Competitive Providers, Beginning of December 2000

	CMP	BHE	MPS
Residential & Small Commercial	<1%	<1%	8%
Medium Class	14%	3%	64%
Large Class	68%	29%	73%
Total	33%	12%	38%
Total load served in state: 30%			

Customers Served by Competitive Providers, Beginning of December 2000

	CMP	BHE	MPS
Residential & Small Commercial	129	37	1680
Medium Class	928	38	111
Large Class	148	7	11
Total	1205	82	1802
Total customers in state: 3089			

During the first year of open access, few aggregation groups targeting residential customers have developed. One residential aggregation group began actively soliciting customers and various internet-based companies operate in Maine, but none of these groups purchases on the open market yet. Only one licensed marketer actively solicits residential sales. The high transaction costs associated with serving residential customers, the lack of residential aggregation throughout other New England states, and a relatively low standard offer rate in CMP's and MPS's territories undoubtedly contribute to the slow growth in residential sales.

Portfolio Requirement

Pursuant to the Restructuring Act and Commission rule, 30 percent of each competitive provider's electricity sales in Maine must be generated by "eligible resources." Eligible resources are defined as renewable resources and cogeneration facilities constructed prior to 1997 that meet a stated efficiency standard. Chapter 311 of the Commission's rules, which implements the portfolio requirement, specifies that the requirement must be satisfied over each calendar year and requires providers to submit annual reports demonstrating compliance.

As part of its general responsibility to oversee the functioning of Maine's retail electricity market, we have monitored the operation of the portfolio requirement. At this point, it appears that competitive providers are acting in good faith to comply with the requirement. We will be able to verify compliance more definitively when providers file their first annual reports on May 1, 2001.

We have also monitored the cost of the requirement to Maine's electricity customers as well as its benefits to the State. At this point, it appears that the portfolio requirement may result in a substantial premium on the retail cost of electricity, without any clearly identifiable benefits to the State. Because of the nature of the portfolio requirement, it is difficult to determine with any degree of certainty either the cost of the requirement or the benefits it produces. However, based on prices offered to Maine utilities that sought standard offer supply, discussions with providers, and comments in the recent standard offer rulemaking, the portfolio requirement may be increasing the cost of generation services by 1% to 10% (or approximately 1 to 5 mills). Additionally, we have very little indication that the premium is supporting Maine facilities or causing eligible facilities to generate that would not have otherwise operated. It also appears that the portfolio requirement may be causing a barrier to entry into Maine's market for some potential providers.

Because we are concerned about these indications, we explored the possibility of submitting legislation to replace the resource portfolio requirement with a system benefit charge. Under this proposal, utilities would include in their rates a charge that would produce funds to be distributed to eligible resources based on a periodic bidding and selection process. We distributed this suggestion to interested stakeholders, who signaled very little support. We concluded that, with time, the market for eligible resources might mature and that changing the current procedure might be premature. In particular, a planned regional Generation Information System will facilitate a more transparent market for specific fuels. However, we will continue to monitor both the costs and benefits of the portfolio requirement and provide the Committee with reports on its operation.

Disclosure Labels

The Restructuring Act requires us to adopt a mechanism for providing information to customers that will enhance their ability to effectively make choices in the competitive electricity market. Chapter 306 of the Commission’s rules requires all providers to distribute “uniform disclosure labels” to their residential and small commercial customers every three months.³ The utilities prepare and distribute the labels to standard offer customers.

The disclosure labels make it easy for customers to compare electricity offers by presenting relevant information in a consistent manner. The labels contain average price, resource mix, and emissions data compared to regional averages. The majority of Maine’s electricity consumers who are taking standard offer service received their first labels in September. We have received very few consumer questions regarding the label, so it is difficult to determine the extent to which consumers are responding to the information. Representative labels are shown in Appendix B.

III. STANDARD OFFER SERVICE IN YEAR 1

During 2000, standard offer service was available to all Maine consumers, as required by law. Standard offer service was provided in part by providers chosen through a Commission-run competitive solicitation process and in part by the incumbent T&D utilities.⁴ Specifically, during 2000, more than 80% of Maine’s consumers had access to standard offer service provided directly by a retail provider chosen through our solicitation. However, because this solicitation did not yield acceptable bids for all classes and service territories, we directed CMP and BHE to procure power supply and provide the additional standard offer service needed.

The table below summarizes the standard offer service providers and average prices at the beginning of open access.

Standard Offer Providers and Average Prices on March 1, 2000

	Residential and Small Commercial Class		Medium Class		Large Class	
	Provider	Ave Price ¢/kWh	Provider	Ave Price ¢/kWh	Provider	Ave Price ¢/kWh
CMP	Energy Atlantic	4.089	CMP	5.9	CMP	5.2
BHE	BHE	4.5	BHE	4.9	BHE	4.9
MPS	WPS-ESI	4.2906	WPS-ESI & Energy Atlantic	4.2549	WPS-ESI	4.0038

³By statute, providers must also provide comparable information to all their larger customers once a year.

⁴The consumer-owned utilities (COUs) procured standard offer suppliers through their own competitive solicitations.

Because of the utilities' role in providing standard offer service, we monitored utilities' procurement decisions and ensured that standard offer prices remained reflective of the underlying power supply costs. The power supply strategies used by CMP and BHE were different. CMP's strategy was to lock in most components of its supply and price up-front by securing a fixed price, full requirements contract with a wholesale supplier. BHE used a portfolio approach whereby standard offer supply was provided with a blend of wholesale contracts and spot market purchases. The process and results of each approach are described below.

Central Maine Power Company

In late 1999, CMP issued a request for proposals (RFP) for fixed price full requirements wholesale power supply for the standard offer requirements of its medium and large customer classes. CMP evaluated proposals it received, reported the results to the Commission and Public Advocate, negotiated with the bidders whose proposals appeared to yield the lowest cost and risk, and recommended entering into a contract with a supplier. We found that CMP acted prudently, directed CMP to enter the contract as recommended, and set standard offer prices for the medium and large classes as proposed by CMP.

In December 2000, CMP filed a request to increase standard offer prices to medium and large customers, to reflect an increase in the costs associated with purchasing Installed Capability (ICAP) in support of standard offer service. We approved a lesser increase, to be effective in January and February 2001.

Standard Offer prices for CMP's medium and large customers during the first year of standard offer service are:

CMP Standard Offer Prices March 2000 – December 2000

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Medium Class	5.52	6.81
Large Class		
On-Peak	5.925	11.041
Off-Peak	3.3783	3.8823

CMP Standard Offer Prices in January - February 2001

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Medium Class	6.4	N/A
Large Class		
On-Peak	6.6327	N/A
Off-Peak	4.0860	N/A

Bangor Hydro-Electric Company

In late 1999, BHE conducted an RFP process to acquire standard offer power supply for its service territory. After reviewing the proposals submitted, BHE proposed a portfolio approach whereby it would enter into a contract with a wholesale supplier and acquire the remaining power supply on the spot market. The wholesale supplier contract would serve approximately 60% of the standard offer load, leaving 40% to be served by the ISO-NE regional spot market. We found that BHE had acted prudently and approved BHE’s strategy. We also directed BHE to monitor the wholesale market and actively manage its portfolio and noted that we would closely monitor BHE’s actual supply costs and consider modifying standard offer prices if they did not reasonably reflect costs.

Because BHE’s standard offer supply was partially purchased from the spot market, extraordinary high market price spikes in May and uncertainty in the ICAP market necessitated two adjustments during 2000. In July the Commission approved revised prices to increase standard offer revenues by approximately 1.7%. In September, the Commission approved a 32.5% increase in BHE’s standard offer prices.⁵ Despite these price increases, standard offer prices remain lower than they would have been if BHE had accepted any of the fixed price bids it received, and they remain lower than any bids offered by competitive providers in the standard offer solicitation process.

BHE’s standard offer prices in March 2000 and in December 2000 are:

BHE Standard Offer Prices on March 1, 2000

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	4.5	4.5
Medium Class	4.624	5.704
Large Class		
On-Peak	5.314	7.459
Shoulder	4.680	6.829
Off-Peak	3.848	4.117

BHE Standard Offer Prices beginning August 2000

	August	September (non-summer)	October – February (non-summer)
Residential/Small Commercial	4.608	4.608	6.106
Medium Class	6.127	4.967	6.127
Large Class			
On-Peak	7.982	5.687	7.041
Shoulder	7.308	5.008	6.201
Off-Peak	4.406	4.118	5.100

⁵An increase of 32.5% in the standard offer resulted in an overall average increase of 10.5% to residential bills.

Chapter 301 Rulemaking

During 2000, we conducted three rulemaking proceedings involving the standard offer rule (Chapter 301). First, beginning in June 2000, we issued a Notice of Rulemaking, received comments from a wide variety of stakeholders, and surveyed providers that participated in the 1999 competitive solicitation process. In August 2000, we adopted an amended Standard Offer Rule that improved the solicitation process and increased the likelihood of successfully choosing standard offer providers for all classes at reasonable standard offer prices.

In October 2000, we initiated an emergency rulemaking to consider amendments to the rule that would close a loophole inadvertently introduced when the rule was amended in August. The loophole would have allowed customers and non-standard offer suppliers to arbitrage standard offer service by, in effect, reselling it into the higher priced regional forward power market.⁶ Because this arbitrage opportunity was not intended when the rule was amended in August, and it could adversely impact current standard offer providers and future standard offer bid prices, we amended the rule on an emergency basis.

In November 2000, we again initiated a rulemaking to more permanently determine the opt-out provisions of the rule. Because, by law, the amendments adopted on an emergency basis would be in effect only for 90 days, a rulemaking was needed to consider provisions that would govern this aspect of standard offer service after the emergency rule expires.

Current Standard Offer Solicitation

On October 2, 2000, we issued RFPs for suppliers to provide standard offer service for CMP, BHE and MPS customers for the period beginning March 1, 2001.⁷ On December 1, qualified bidders began submitting price bids. Because of the volatility of the wholesale electricity market, bidders wished to submit bids that were open for only a short period of time and to resubmit new bids after that time had expired. We allowed this procedure, and therefore considered bids on a daily basis. On December 11, we accepted a winning bidder for MPS's territory but have kept the bid price and the name of the bidder confidential to avoid placing the bidder at a disadvantage while it secures its supply.

During December, two events exerted a dramatic and undesired impact on the bids we received. First, prices in the natural gas commodity market fluctuated significantly, causing electricity prices to spike in response. In

⁶The loophole resulted from the provisions governing opt-out penalties that discourage medium and large customers from strategically moving between standard offer and the competitive market.

⁷Some consumer-owned utilities' standard offer service will be provided as part of this solicitation. Other COUs' service will continue to be served under existing contracts.

addition, the FERC issued a decision that set the cost of ICAP deficiency at a higher level than many had anticipated. We believe that the first event is transitory and that the second event has some likelihood of being reversed. Therefore, we ruled that it would be a disservice to the consumers of Maine to accept bid prices that reflect the uncertainties created by the events. Currently, we continue to accept bids and we simultaneously have directed CMP and BHE to explore wholesale power supply arrangements that would allow the utilities to provide standard offer service.

IV. WHOLESALE MARKET AND TRANSMISSION ISSUES

We continue to fulfill our obligation under the Restructuring Act to monitor events in New England's wholesale markets. We have participated in the rulemakings and deliberations of various New England Power Pool Committees, monitored the progress of the Independent System Operator, initiated, intervened and commented on important cases at the Federal Energy Regulatory Commission, met individually with representatives from each of the market sectors, significantly expanded the time commitment from our own staff to understand and address emerging market issues, and worked collaboratively with regulators from other New England states to enhance the uniformity of markets in the different states and to improve the states' effectiveness in negotiating within and litigating before regional and national organizations.

Because regional activities significantly impact the electricity prices of Maine's consumers, this report will provide explanations of regional entities and procedures, as well as Commission activities.

NEPOOL

The New England Power Pool (NEPOOL) is a voluntary organization of entities engaged in the power markets, that interact with each other according to a set of formalized rules called the NEPOOL Agreement. NEPOOL has five membership sectors; they are: transmission owners, load providers, public power companies, generators, and end use customers. The NEPOOL Agreement covers the market operation rules and also the regional open access transmission tariff (OATT). Standing committees develop the market rules and the transmission tariff, oversee the bulk power system's reliability, and attempt to develop consensus on filings with the Federal Energy Regulatory Commission (FERC). We actively participate at the NEPOOL Committee meetings. Through the committee process, we support positions that provide greater market transparency and information disclosure and rules that provide increased opportunities for competitive entry. We choose our positions carefully based on principles that will advance the interests of Maine's consumers and promote the development of competitive retail markets in Maine. Regulators do not have a

vote at NEPOOL,⁸ but their views are considered because of Maine's active participation at the FERC and FERC's interest in state perspectives.

ISO-NE

The New England power grid comprises 8,000 miles of transmission lines that are owned by seven regulated transmission companies and 330 generating stations that are owned by unregulated companies. A system operator maintains grid reliability by coordinating the operation of all of these facilities. The mix of regulated transmission utilities with unregulated generation and load serving companies that now exist in the region requires a system of commercial rules to guide the operation of the system. The Independent System Operator of New England (ISO-NE) was formed in 1997 to maintain system reliability and to ensure that the operating rules developed by the NEPOOL Committees are applied to the mixture of transmission and generation facilities in a manner that is fair and impartial to all. ISO-NE also has responsibility for ensuring the competitiveness of New England's wholesale markets, and has the authority to monitor the markets and to mitigate certain types of behavior. When the market rules developed by NEPOOL threaten either the reliability of the system or competitiveness of the market, ISO-NE has the authority to unilaterally change the rules that may only be reversed by the FERC. We have supported ISO-NE when it has exercised this authority and when its authority has been challenged at the FERC. We have also been critical of the ISO-NE when it has appeared that the agency was reluctant to exercise its authority as intended. Over the past year, we have held numerous meetings and phone calls with high level ISO-NE employees to discuss specific market problems and ISO-NE representatives have twice traveled to Augusta to explain their positions to the Commissioners in person. The focus of many of these meetings was the ICAP market, of which the Maine Commission and other market participants have been highly critical.

Federal Energy Regulatory Commission Activity

The FERC regulates transmission pricing and has the authority to approve the market-based rates under which the New England and northern Maine markets operate. As a result, all of NEPOOL's market rules, ISO-NE's interpretation of the rules, and decisions about who plans, builds, and pays for transmission are under FERC jurisdiction. The rapid pace of change to the NEPOOL rules necessitated by the move to markets has greatly increased the number, complexity, and contentiousness of the filings before the FERC. The Commission has reacted by devoting more of its legal staff time to monitoring and participating in these proceedings, and has retained the services of expert FERC counsel based in Washington D.C. A brief summary of some of these

⁸The Commission did, however, assist the State Planning Office to become a voting member.

proceedings is provided below. A summary of all FERC cases in which we have participated is contained in Appendix C.

- Transmission Pricing: All of Maine's utilities were involved in filing "formula based" transmission rates. Commission staff and our FERC counsel were instrumental in negotiating a settlement among the parties, which included ratepayers, independent power producers, and transmission companies.
- ISO Authority: ISO-NE re-calculated the clearing prices in the Operable Capability (OPCAP) market for certain days in the summer of 1999. Rules for the market were poorly written and ISO-NE's rule interpretation caused prices to drop from \$1600/MWh to \$3/MWh. We filed comments in support of the ISO-NE's interpretation of the rules when it was challenged at the FERC by some merchant generators. FERC agreed with the position adopted by ISO-NE and supported by the Commission. The OPCAP market was later eliminated due to this and other problems.

ISO-NE's authority has also been challenged by INDECK, an independent generator located in Maine. ISO-NE instructed the generator to run, but refused to pay the price INDECK had bid because it believed the pattern of the company's bidding demonstrated an intentional effort to raise clearing prices. We supported ISO-NE's exercise of its authority. FERC did not agree, and instructed ISO-NE to modify its method of mitigating such behavior in the future.

ISO-NE was also challenged when it re-settled prices in the ICAP market. Starting in November of 1999, the bid prices in this market increased from near zero to as high as \$9,999/MW for no readily apparent reason. ISO-NE determined that there had been "anomalous conduct in the market" and re-settled the prices back to zero. Had ISO-NE not acted, the higher costs would have dramatically affected consumers receiving standard offer service in Maine. We supported ISO-NE's initial action and continue to support it in subsequent, ongoing legal challenges at FERC.

- NEPOOL Rules: As mentioned above, the NEPOOL rules are undergoing rapid change. NEPOOL filings at FERC, which at one time were largely consented to by all parties, have become much more contentious. We have been actively involved in a number of such proceedings, and are currently working with NEPOOL participants to make changes to ISO-NE's market monitoring and mitigation authority. The changes, which were mandated by the FERC, affect consumers because they will determine when ISO-NE can act to mitigate the exercise of market power. We have also intervened in FERC proceedings and urged the FERC to allow greater freedom of transactions with other electrical grids such as those in New York, Quebec, and New Brunswick. Increasing the number of supply sources to New

England will reduce market concentration, increase competition, and drive energy prices lower for consumers.

- Price Spikes: When energy prices in the New England spot markets reached \$6,000/MWh (\$6.00/kWh) for four hours on May 8, 2000, we wrote to the Chairman and CEO of ISO-NE requesting a detailed and specific explanation for why such prices would occur in a competitive market. When the answer from ISO-NE indicated that the prices resulted largely from the ways in which market rules had been interpreted rather than from market fundamentals, we filed a complaint at the FERC challenging ISO-NE's interpretation of the rules and seeking a recalculation of the prices for the hours in question. We also filed comments at FERC supporting the requests of other parties for the imposition of price caps on the New England market.

Regional Transmission Organization

The FERC has directed T&D utilities and ISO-NE to develop a proposal for an independent Regional Transmission Organization that would perform planning, market monitoring and inter-regional coordination of the region's transmission system. In coordination with other states, we have been active in the negotiations being held to develop this proposal.

Collaboration with Other States

The New England Conference of Public Utilities Commissioners (NECPUC) provides an opportunity for the commissioners of different states to share information and collaborate on solutions to regional issues. NECPUC has created a NEPOOL "Coordinating Committee" which meets regularly to discuss wholesale electric market issues. The group attempts to prevent the balkanization of individual state markets by maintaining uniformity among the rules of different states. The goal of this strategy is to reduce the costs of doing business for suppliers thereby reducing prices to consumers.

NECPUC provides a vehicle for pooling resources. The coordinating committee has developed a work plan that spreads the responsibility for covering various market issues among different states to economize the use of staff resources. The Maine Commission leads the effort to develop and file consensual NECPUC positions at FERC on market issues in the belief that a unanimous position by all six New England states will carry greater weight with the agency than one state speaking alone.

Northern Maine Independent System Administrator

The northern part of the State⁹ is not directly connected to New England's electric grid. Northern Maine operates as part of the Maritimes Control Area and receives power through transmission facilities owned by New Brunswick Power Company. As a result, the scheduling, market procedures, and financial settlement performed by ISO-NE does not extend to the northern Maine market.

Prior to 2000, the Northern Maine Independent System Administrator (NMISA) was created to schedule the northern Maine transmission system, and to develop and enforce market rules and operating procedures that ensure the integrity of transmission capacity availability and guarantee non-discriminatory markets for balancing energy and ancillary services. We monitored the northern Maine market and NMISA operation during the year and observed that the market appears to be functioning reasonably well.

V. OTHER RESTRUCTURING ITEMS

Additional activities required by the restructuring process are described below.

Consumer Education Program

During 2000, we continued implementation of the electric restructuring consumer education program. The program, launched in 1998, satisfies both a Legislative mandate that the Commission provide education about electric choice and our own desire to ensure that consumers are informed about changes in the industry before they make electricity supply purchasing decisions.

The program provides information to residential, small commercial and municipal consumers. The program uses a variety of complementary educational methods in an integrated fashion, to reach the broadest audiences. A broad-based public advisory panel has assisted us in program design and implementation.

During 2000, we completed implementation of the third phase of the program to coincide with the beginning of competition in March. We continued advertising on TV, radio and in newspapers to raise general awareness of restructuring, and sent direct mail reference guides to all residential and small commercial consumers in Maine in January 2000. We hosted several community fora in early 2000 and continued to support outreach by selected community-based organizations. The electric choice Speakers' Bureau, composed of senior Commission staff, also continued to speak to groups across the state, and has now reached more than 3,500 consumers.

⁹Within this context, northern Maine includes the service territories of MPS, Eastern Maine Electric Cooperative, Van Buren Light and Power and Houlton Water Company.

As March 2000 approached, the education campaign increased in intensity. When it became clear in early January that the speed of competitive market development in the residential sector would be slower than expected, however, we slowed the education campaign. Responding to advice from the Advisory Panel, we deferred some planned investments in advertising, newsletters, and other educational activities, to preserve resources in case additional educational activities are necessary as the competitive market develops.

Research results from Spring 2000 show that, despite being scaled back, the campaign increased consumer awareness and understanding of restructuring. For example, general awareness increased from 47% in 1998 to 73% in 2000; consumers who felt “fairly well” or “very well” informed increased from 16% in 1998 to 51% in 2000; and consumers who knew that they would automatically receive Standard Offer if they did not choose a provider increased from 43% in 1998 to 84% in 2000. Research from September 2000, however, suggests that these advances in awareness and knowledge are dropping slightly now that active outreach has stopped, suggesting that, once competition for residential consumers picks up, additional education will likely be appropriate.

Information is available on the toll-free PUC Electric Choice Information Line at 1-877-PUC-FACT (1-877-782-3228) and the PUC Electric Choice website at www.pucfact.com.

Low-Income Program

The Restructuring Act requires the adequate provision of financial assistance to meet the legitimate needs of consumers who are unable to pay their electricity bills. The Act further requires that those funds be collected by utilities at a rate set by the Commission and that funding be based on an assessment of aggregate customer need. 35-A M.R.S.A. § 3214.¹⁰

Since 1999, we have participated in a Low Income Task Force whose purpose is to determine the most effective way to establish a needs-based, low-income assistance program for electric utility customers. In accordance with the time table set by the task force, we will conduct a rulemaking during early 2001 to develop a statewide program to be implemented by October 2001. In the meantime, the task force is developing procedures that will form the basis for the draft rule and we are gathering data to determine the level of need. Until October 2001, the investor-owned utilities will continue their existing low-income assistance programs.

¹⁰During an earlier session, the Legislature considered, but did not accept, a proposal to use divestiture tax income to fund low-income assistance.

Rulemakings

Except for the standard offer rule change mentioned above, we did not make major changes to our rules. We will continue to monitor the operation of the rules to ensure they are achieving the objectives of the Restructuring Act, and propose rule changes when warranted.

All the electric restructuring rules are listed in Appendix D.

Competitive Billing and Metering

The Restructuring Act required implementation of competitive billing and metering by March 1, 2002. During 2000, the Legislature revised the statute, allowing the Commission to determine the appropriate time to implement competitive billing and metering and the customers to whom competition should apply. P.L. 1999, ch. 601. Based on current marketplace conditions, the Commission does not intend to initiate rulemaking activity on this issue during 2001.

Demand-Side Management

Maine law directs the State Planning Office (SPO) to develop, coordinate and oversee statewide conservation programs. P.L. 1999, ch. 336. During 2000, SPO solicited input from stakeholders on appropriate program content. SPO anticipates that program plans will be completed in early 2001 and that implementation will begin during late 2001.

Voluntary Renewable Resource Research and Development Fund

The Restructuring Act requires that electricity consumers be allowed to contribute to a program that funds renewable resource research and development and demonstration projects. 35-A MRSA § 3210. In September 2000, most utilities notified their customers of this provision and began collecting customers' voluntary contributions. At this time, contributions have been minimal, so no projects have yet been funded.

Web Site

We have continued to expand our two easily accessible, user-friendly, targeted web sites – one for consumers and one for competitive providers.¹¹ The consumers' site was extensively advertised through a variety of media. The competitive providers' site includes details on all aspects of restructuring that providers need for effective operation in Maine. Providers have commented

¹¹The consumer web site is www.pucfact.com and the supplier web site is janus.state.me.us/mpuc.

favorably on the usefulness of their web site, which has further contributed to making Maine an easy place to establish business operations.

VI. MEGA-CASES - REVENUE REQUIREMENT, STRANDED COST AND RATE DESIGN

T&D Rates

The Restructuring Act directed the Commission to establish the revenue requirements, including the level of generation related stranded costs, for each T&D utility prior to the onset of retail access. The Restructuring Act also directed us to design the rates that utilities would charge for T&D-only service. These revenue requirement, stranded cost and rate design proceedings (also referred to as the “mega-cases”) were substantially completed during 1999. However, compliance and update phases were completed during the first two months of 2000 and T&D rates for each of the State’s investor-owned utilities were put in place by March 1, 2000. The Commission also set T&D-only rates as of March 1, 2000, for all but three of the state’s consumer-owned utilities.

The total adjusted test year revenue requirement established for CMP was \$415,130,000, consisting of a T&D revenue requirement of \$269,251,000 and a stranded cost revenue requirement levelized over a two-year period of \$145,879,000 per year. On average, the total rate that CMPs’ customers paid for electricity decreased by 9.8% when compared to the pre-restructuring bundled rates. In addition, we changed the structure of the standard residential rate. Under CMP’s prior rate structure, the kWh charge increased by 25% after the first 400 kWhs of usage. This rate was levelized and the T&D rate for residential customers was set at 7.74¢/kWh for all kWhs used.

BHE’s overall revenue requirement was set at \$103,187,000, consisting of a T&D revenue requirement of \$63,596,000 and a stranded cost revenue requirement of \$39,591,000 per year. We estimated that, assuming all customers took standard offer service, the average total rate for electricity for BHE customers would decrease by 2.4% at the start of restructuring. BHE’s rate for residential T&D service was set at \$9.5¢/kWh.

MPS’s overall revenue requirement was set at \$29,143,000. The T&D revenue requirement was set at \$16,640,000 and, for the period of March 1, 2000 through March 1, 2002, the annual stranded cost revenue requirement was set at \$12,503,000.

MPS’s standard residential rate was also changed from an inclining block rate to a levelized per-kWh rate. This was accomplished without increasing the monthly bill of any residential customer. Compared to the pre-March 1, 2000 bundled electric rates, MPS customers achieved the following class average decreases:

Residential	8.2%
Small Commercial	3.7%
Medium Commercial & Industrial	4.6% to 4.8%
Large Commercial & Industrial	4.6% to 5.2%

The overall average decrease for MPS core customers was 6.1%.

Consumer-Owned Utility Rates

On January 31, 2000, the Commission issued orders approving T&D rates for Eastern Maine Electric Cooperative, Houlton Water Company, Kennebunk Light & Power District, Fox Island Electric Cooperative, Madison Electric Works, Swans Island Electric Cooperative and Van Buren Light & Power District. Because these COUs are owned and managed by their customers and because their customers are accustomed to monthly rate changes that reflect purchased power costs, the Commission permitted a more significant level of revenue re-allocation and rate re-design than in the case of CMP, BHE or MPS.

Matinicus Plantation Electric Company and Monhegan Plantation Power District are exempt from the requirements of the Electric Restructuring Act. In addition, because of its remote island location and status as a small COU (less than 150 customers), we granted Isle Au Haut an exemption from the provisions of the Electric Restructuring Act.

Special Rates and Contracts

Before restructuring occurred, CMP, BHE and MPS operated under alternative rate plans or flexible pricing plans that allowed the utilities flexibility in offering reduced or special rate contracts to individual customers. Each alternative rate plan terminated by March 1, 2000. However, many of the special rate contracts entered into under the plans were extended beyond that time or were renewed during 2000. These contracts were unbundled into a generation portion whose price reflected a diligently-purchased open-market generation price. The remaining portion of the contract price was attributed to T&D service. Special targeted rates that were developed under the alternative rate plans and were deemed to be needed after restructuring were unbundled using a similar approach.

Federal Jurisdiction Over Transmission

The FERC has concluded that when a state unbundles the generation component from total electricity prices and allows generation services to be purchased separately from transmission and distribution services, the FERC obtains jurisdiction over retail transmission rates, terms and conditions. As a result, we initiated an investigation to identify all assets of Maine utilities that should appropriately be categorized as transmission, as well as all costs that should be considered transmission-related. As part of this effort, we completely

separated all transmission-related costs from our jurisdictional rate-setting authority and established distribution-only rates.¹²

Because the FERC asserted jurisdiction over retail transmission rates on March 1, 2000, CMP, BHE, and MPS filed for FERC approval of their proposed transmission rates. Each utility asked FERC to adopt a formula rate, that would be updated each year. We intervened in each of the utility's proceedings, acting on behalf of retail ratepayers to ensure that their transmission rates would be just and reasonable. Due to various factors, including increases in regional costs that flow through transmission rates and new transmission investment, the utilities' FERC proceedings resulted in a small increase in consumers' delivery rates.

As a result of these proceedings, the utilities now have formula rates under which their transmission charges will be updated each year. We will analyze each utility's annual filing to ensure that the formulas have been properly implemented. We will also monitor the operation of the formulas to determine if they are producing just and reasonable rates. If this is not the case, we will petition the FERC to correct the problems.

VII. EXPENSES OF AFFILIATED TRANSACTIONS

The Restructuring Act requires us to assess our actual and estimated future costs of implementing the law governing the relationship between a utility and an affiliated competitive provider, and the costs to utilities in complying with those provisions. 35-A M.R.S.A. § 3217(1). 35-A M.R.S.A. § 3205 establishes the standards of conduct and marketing restrictions applicable to investor-owned utilities that market electric energy through an affiliated competitive provider. Chapter 304 of the Commission's Rules expands upon these standards.

MPS's subsidiary, Energy Atlantic, is the only affiliated competitive provider in the State. As a consequence, our cost of enforcing the affiliate standards of conduct in 2000 has been minimal, consisting of reviews of periodic reports required pursuant to Chapter 304. MPS also estimates that it has incurred minimal costs to comply with affiliate transaction rules. However, on October 31, 2000, WPS-ESI filed a complaint against MPS alleging violations of the affiliate standards of conduct and associated Commission rule. It is too early to estimate the expense to the Commission or to MPS of investigating this complaint.

Chapter 304 requires annual audits to be conducted to determine compliance with the standards of conduct. We will conduct the first audit after the completion of one year of retail access. The cost of the audit is not likely to be significant.

¹²The distribution-only rates include stranded costs.

The subsection also directs us to assess the effect of these compliance costs on ratepayers and shareholders of the utility. Commission expenses and MPS expenses have caused no impact on customers' rates.

VIII. CONCLUSION

We acknowledge and appreciate the hard work and cooperative spirit shown by the Legislature, the utilities, the competitive electricity providers, the Public Advocate and other intervenors, and our own staff during 2000. Through their efforts, the competitive electricity market was introduced successfully to all Maine's consumers on March 1, 2000. 30% of Maine's load has migrated to the open market. Standard offer rates for smaller consumers, coupled with utilities' delivery rates, allowed total bills to decrease for almost all customers on March 1, 2000.

The second year of restructuring, beginning March 1, 2001, promises to be challenging. Sharp increases in fuel costs (especially natural gas, used to power much of New England's generation), continuing instability and flawed rules in the wholesale markets, and FERC's recent decision to raise the price for ICAP are all likely to contribute to substantial increases in the price of electricity supply for many of Maine's residential consumers and most if not all of Maine's businesses. We continue to work with others in and outside of Maine to try to bring effective and efficient competition to the regional wholesale markets as well as Maine's retail market. The success of those efforts will be vital in bringing the long-term benefits of electric restructuring to Maine's citizens.

Appendix D

Commission Rules Related to Electric Restructuring

Chapter 301: Standard Offer Service

Chapter 302: Consumer Education Program: Electric Industry Restructuring

Chapter 303: Utility Employee Transition Benefits

Chapter 304: Standards of Conduct for Transmission and Distribution Utilities and Affiliated Competitive Electricity Providers

Chapter 305: Licensing Requirements, Annual Reporting, Enforcement and Consumer Protection Provisions for Competitive Provision of Electricity

Chapter 306: Uniform Information Disclosure and Informational Filing Requirements

Chapter 307: Sale of Capacity and Energy; Extensions for Divestiture of Assets

Chapter 309: Bill Unbundling and Illustrative Bills

Chapter 311: Eligible Resource Portfolio Requirement

Chapter 312: Voluntary Renewable Resource Research and Development Fund

Chapter 313: Customer Net Energy Billing

Chapter 321: Load Obligation and Settlement Calculations for Competitive Providers of Electricity

Chapter 322: Metering, Billing, Collections, and Enrollment Interactions Among Transmission and Distribution Utilities and Competitive Electricity Providers

Chapter 323: Electric Business Transactions Standards

Chapter 360: Cogeneration and Small Power Production

Chapter 380: Demand Side Energy Management Programs by Electric Utilities

Chapter 820: Utility Requirements for Non-Core Activities and Transactions Between Affiliates

Appendix E

35-A M.R.S.A. § 3217(1) directs the Commission to report on activities relating to changes in the regulation of electric utilities in other states. The Energy Information Administration maintains a website that describes the status of state electric restructuring efforts. The contents are too voluminous for this report, but may be accessed on (http://www.eia.doe.gov/electricity/chg_str/tab5rev.html).