MAINE STATE LEGISLATURE

Maine Public Utilities Commission

2007 Annual Report on Electric Restructuring

Presented to the
Utilities and Energy Committee
January 15, 2008

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2007 Annual Report on Electric Restructuring
Presented to the Utilities and Energy Committee of the Maine Legislature

I. INTRODUCTION

During its 1997 session, the Legislature enacted P.L. 1997, ch. 306 (the Restructuring Act), which directed the comprehensive restructuring of Maine's electric utility industry, including divestiture of generation supply assets and functions from the regulated utilities, moving, instead, to a competitive market regime for these services. Since March 1, 2000, Maine utilities have been transmission and distribution (T&D) companies only and Maine consumers have had the right to purchase retail electricity supply in the market. In addition to continued regulation of T&D utilities, since the Restructuring Act the Commission also oversees Maine's retail electricity market, procures standard offer service, and participates in regional wholesale market activities that affect Maine's electricity consumers.

Pursuant to the Restructuring Act, the Commission submits this report to the Legislature's Joint Standing Committee on Utilities and Energy describing issues and events related to the Restructuring Act for the year 2007.

Key Events and Issues

- Wholesale electricity prices in the region continued to closely track natural gas. Electricity prices in the spot market were about 10% higher in 2007 relative to 2006, although prices in the forward market tended to be lower. Wholesale prices in Maine continued to be lower than in other New England states due to an excess of in-state supply.

- At the Legislature's directive, the Commission analyzed Maine's participation in the New England Regional Transmission Organization and potential alternatives. The Commission concluded that the *status quo* would not allow Maine or the region to meet important policy and environmental goals, and presented three alternatives for consideration by the Legislature.

- On February 8, 2007 Governor Baldacci and Premier Graham of New Brunswick signed a *Memorandum of Understanding between the Province of New Brunswick and The State of Maine to Enhance the Mutual Benefits of the Maine/New Brunswick Electrical Interconnections*.

- After concluding in late 2006 that competition was failing in Northern Maine, the Commission, with significant involvement by stakeholders, considered and analyzed several responsive measures.

- In Maine's retail market, large and medium sized commercial and industrial customers maintained a reasonable and steady level of migration to the retail

supply market, while virtually all residential and small commercial customers continued to receive standard offer service.

- The number of retail suppliers serving Maine customers was stable, with several companies supplying load during 2007. In addition the market share profile improved. Although a large share of the retail market continued to be served by a set of affiliated suppliers, the market share of these companies dropped significantly compared to prior years.

- The Commission conducted five standard offer solicitations during 2007.

- The Commission adopted Long-Term Contracting and Resource Adequacy rules (Chapter 316) to implement statutory changes that authorize long-term contracting for capacity resources and direct the establishment of a resource adequacy plan.

- The Commission adopted rules (Chapter 311) to implement the new renewable resource portfolio requirement.

- Distribution, transmission and stranded cost rates remained relatively stable during 2007.

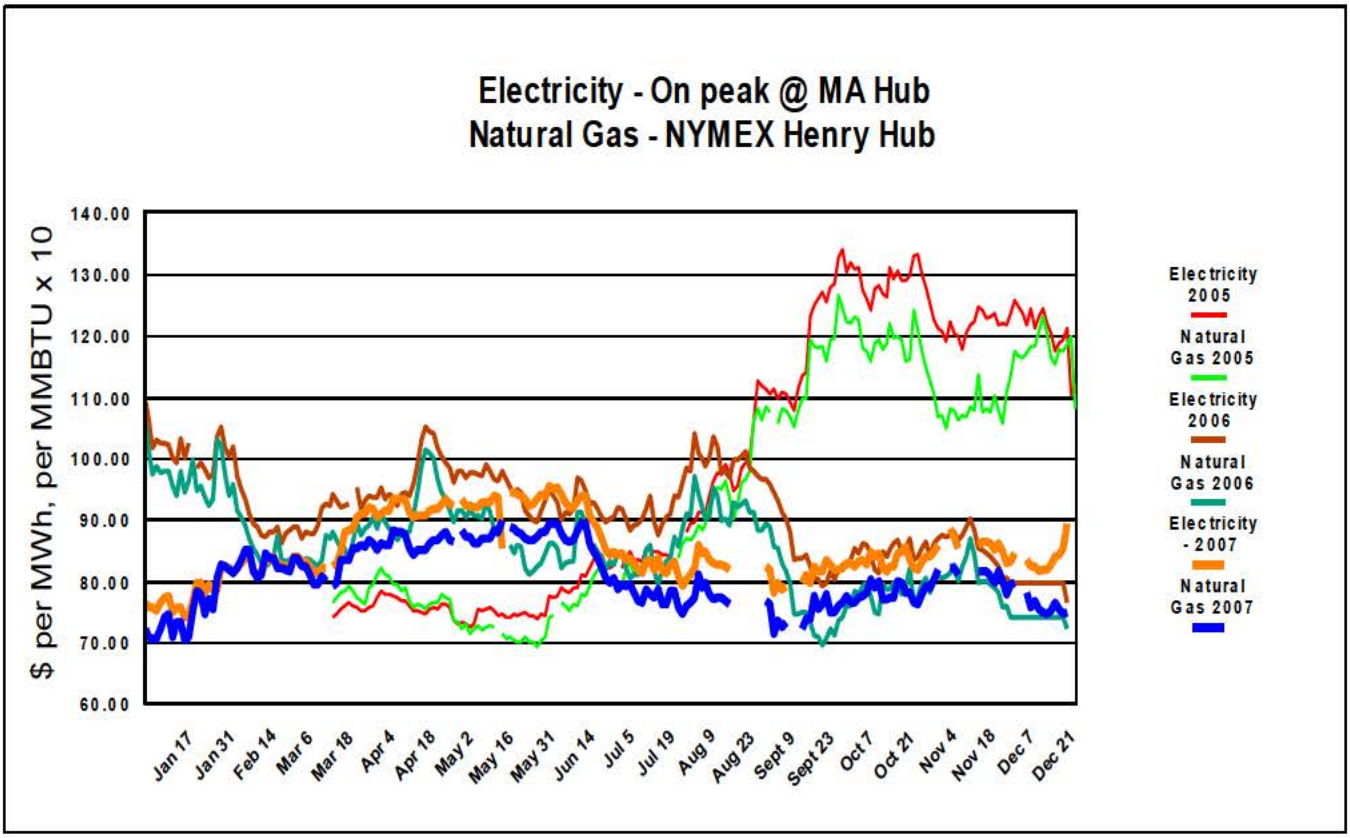
II. REGIONAL WHOLESALE MARKET AND RELATED ACTIVITY

When Maine restructured its electricity market, it became part of a broader regional market for wholesale electricity. In recognition of this, in 1997 the Legislature enacted 35-A MRSA §3215, which directs 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 Independent System Operator-New England (ISO-NE) has been the Regional Transmission Organization (RTO) for New England since early 2005. As the RTO, ISO-NE is responsible for the day-to-day operation of the regional grid as well as the administration of regional electricity markets under tariffs and rules approved by the Federal Energy Regulatory Commission (FERC). The Commission participates actively in tariff and market rule development processes, and also intervenes and takes positions at FERC on matters affecting the competitiveness of the wholesale electric markets, reliability, and prices paid by Maine electricity consumers.

Market Prices

As noted above, wholesale electric energy prices in the spot market trended higher in 2007 relative to 2006. However, in contrast, forward prices trended lower in 2007 than 2006. This disparity appears to be attributable to the persistent effect that Hurricanes Katrina and Rita had on the forward price curves into early 2006.



ISO Study

During 2007, the Commission completed its study of Maine's continued participation in the New England Regional Transmission Organization and potential alternatives to continued participation.[1] In its Final Report, the Commission concludes that the *status quo* will not allow the region to meet important policy and environmental goals. The Commission presented three alternatives for consideration. These alternatives are:

1. Market Reform Option

Maine would remain part of a reformed New England RTO and market. Key reforms would address: (1) transmission-related rules, including movement toward a "beneficiary pays" model and resolution of issues around cost allocation for transmission investments that are needed to access remotely-located renewable generation; (2) structural changes to reduce consumer costs; (3) standards needed to

[1] The Legislature directed the Commission study through a Resolve adopted during the 2006 session. Resolves 2005, ch.187.

meet the region's environmental policy objectives; and (4) improvements in economic efficiency.

2. Maine Independence Option

Maine would form an Independent Transmission Company (ITC) to develop, maintain, and manage access to Maine's transmission system. This option would allow for two basic approaches for supplying electricity to Maine consumers. Maine's electricity load could be isolated from the ISO-NE market and supplied by a state-regulated entity. Alternatively, Maine load would not be isolated from the ISO-NE market. This would reduce or eliminate any potential for inadequate competition, thereby making the state-regulated supplier, as described above, optional.

3. Maine/New Brunswick Option

Maine would join with New Brunswick and, possibly, other Canadian provinces. This option has four key elements:

- The New Brunswick System Operator (NBSO) would perform joint dispatch of the bulk power system for the region;
- Transmission systems would be jointly planned;
- There would be a common energy market relying on a hub located in New Brunswick; and
- A state-regulated entity could supply Maine consumers.

The Commission also concluded that it may be possible (and desirable) to develop a hybrid of the Market Reform and Maine-New Brunswick Options such as the creation of an ISO-North that would be treated as part of the ISO-NE energy and operating markets, but which would take a different approach to capacity costs, transmission planning, and transmission cost allocation. This hybrid approach would be designed to reflect the unique role of the Maine-New Brunswick region as an energy export region, particularly for renewable resources.

The Commission's Final Report on continued participation in the New England RTO and alternatives to the *status quo* can be obtained online at http://www.maine.gov/mpuc/staying_informed/legislative/reports.html.

Maine New Brunswick MOU

On February 8, 2007 Governor Baldacci and Premier Graham of New Brunswick signed a *Memorandum of Understanding between the Province of New Brunswick and The State of Maine to Enhance the Mutual Benefits of the Maine/New Brunswick Electrical Interconnections.* Under the document, the governments of Maine and New Brunswick agreed to the following tasks:

1. Study the feasibility of expanding generation capacity and transmission infrastructure to increase electrical flows across borders;

2. Identify processes and systems to provide transparency and efficiency in Maine and New Brunswick markets;

3. Study the feasibility of developing common market rules that could be applied in Maine and New Brunswick;

4. Explore the potential benefits of and potential technical or legal barriers to common provisioning of control area services (including balancing, dispatch and reserve sharing);

5. Explore the tariff and governance structures required for a regional transmission organization for Maine and New Brunswick; and

6. Examine the opportunities for compatible greenhouse gas emissions reduction regimes in the electricity sector.

On June 26, 2007, joint representatives from Maine and New Brunswick submitted the Phase I Report anticipated by the MOU. The report set principles to guide future work, a prioritization of tasks, and a status report on progress to date. After review of the Phase I Report, which reinforced the potential for significant economic and environmental benefits from closer coordination between the regions, the governments agreed to more in-depth study.

During 2007, MOU-related work focused on potential opportunities from expanding generation capacity and transmission infrastructure to increase electrical flows between Atlantic Canada and New England. This task was given the highest priority since a positive outcome is likely to provide the most significant benefits to citizens of Maine and New Brunswick. The effort focuses on clean resources and export opportunities, while identifying potential benefits for the broader region such as (1) meeting demand for electricity and (2) achieving environmental goals to reduce carbon emissions and increase use of renewable resources. The joint representatives anticipate issuing their Phase II Report early in 2008.

Northern Maine

In late 2006, the Commission determined that competition in Northern Maine had failed, after a standard offer solicitation produced only one bidder.[2] During 2007, the Commission, with significant involvement by stakeholders, began a formal inquiry to consider responsive measures. The Inquiry involved a number of meetings with

[2] *Order Rejecting Standard Offer Bids and Directing MPS To Provide Standard Offer Service,* Docket No. 2006-513 (Nov. 16, 2006).

stakeholders and the filing of several rounds of written comments over the course of the year.

On May 3, 2007, the Commission provided a "Report on Northern Maine Electricity Market" to the Utilities and Energy Committee (Committee). The May 3rd Report provided a description of the northern Maine market, a discussion of the 2006 standard offer solicitation, and a status report on the northern Maine market Inquiry. The Report concluded that the status quo in northern Maine is unacceptable and that the northern Maine market, as currently configured, is too small and isolated to support a competitive market. The Commission indicated that it would continue to review alternatives including the feasibility of a transmission interconnection between northern Maine and the rest of New England, options for payments for any new transmission construction, and the potential for long-term contracts as a stimulus for competition. [3]

At the request of the Chairs of the Committee, the Commission, on September 10, 2007, submitted a Report on the Lack of Competition in the Northern Maine Electricity Market. This Report provided the status of the Commission's efforts to address the competitive issues in northern Maine. As discussed in September 10th Report, the Commission continued to meet with stakeholders and seek comments on alternative proposals. [4]

The Commission stated its view that in the longer-term construction of a transmission line that links northern Maine with the New England market appears to be the most straight-forward means to create a liquid electricity market in northern Maine. Maine Public Service Company (MPS) and Central Maine Power Company (CMP) have decided to cooperate in the study of the feasibility of interconnecting northern Maine with the New England region. The project, referred to as the Maine Power Connection, is being studied by the ISO-NE to determine its system impacts and economic benefit. The results of these studies may drive the decision by the ISO-NE on whether to include some or all of the costs of the line in the regional tariff- a decision that would determine whether all ratepayers in New England will share in the costs.

A transmission connection would not be expected to be in service until the end of 2010 or the beginning of 2011 at the earliest. For the interim, the Commission with input from stakeholders has been considering a longer-term standard offer arrangement, aggregating northern Maine with Bangor Hydro-Electric Company's (BHE) electricity load in some manner to attract bidders, use of a transmission reservation

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[3] The May 3rd Report can be obtained on line at http://www.maine.gov/mpuc/staying_informed/legislative/reports.html.

[4] The September 10th report can be obtained on line at http://www.maine.gov/mpuc/staying_informed/legislative/reports.html.

through New Brunswick, and cost-based regulation of wholesale rates. In light of the failed market in northern Maine, the Commission has sought relief from the FERC (which has jurisdiction over wholesale power markets and rates) through a FERC proceeding that is examining the market-based rate authority of Boralex, the entity that owns most of the generation in the northern Maine area.[5] The Commission is awaiting a FERC decision in the case.

The Commission will continue to encourage examination of a transmission link between northern Maine and New England as a longer-term solution and will pursue interim approaches that can be in place before the next series of northern Maine standard offer solicitations.

State Legislative Initiatives

In addition to the ISO study discussed above, the Commission responded to other legislative initiatives related to New England's wholesale electricity market.

Utility Participation in the Energy Supply Business

During the 2007 session, the Legislature adopted a Resolve directing the Commission to review issues involved with T&D utilities entering the energy supply business. The Resolve specified that for purposes of the review, "energy supply business" includes owning, operating or having an interest in electric generation facilities, load management activities or demand-side management activities. The Commission initiated an Inquiry[6] and sought information, viewpoints and recommendations from interested persons through both written comment and a public meeting.

In its Report, the Commission recommends against any immediate legislative changes that would allow the State's utilities to re-enter the business of owning or controlling generation assets.[7] The Commission determined that it is premature to amend the Restructuring Act to reverse one of its basic tenets by allowing utilities to own generation before there has been a sufficient opportunity to test the potential to achieve similar benefits through the long-term contracting mechanism (discussed

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[5] FERC Docket Nos. ER01-2569-005, ER01-4652-005, ER02-1175-004, ER01-2568-003.

[6] *Inquiry Regarding the Reentry of Electric Utilities into the Energy Supply Business,* Docket No. 2007-317.

[7] This recommendation is premised on Maine's utilities remaining a part of the ISO-NE market. To the extent Maine pursues alternatives, the Commission indicated that issues involved with utility ownership and control of generation assets could change dramatically.

below). If the Legislature decides to allow Maine's utilities to re-enter the generation business, the Commission recommends that it do so in the cautious and limited manner described in the Report. The Commission's Report on T&D utility participation in the energy supply business can be obtained online at http://www.maine.gov/mpuc/staying_informed/legislative/reports.html.

Resource Adequacy Plan and Long-Term Contracting

During the 2006 session, the Legislature enacted an Act to Enhance Maine's Energy Independence and Security.[8] One section of the Act (codified at 35-A M.R.S.A. §§ 3210-C, 3210-D)addresses capacity resource adequacy by directing the Commission to establish an electric resource adequacy plan and authorizing the Commission to direct large investor-owned T&D utilities[9] to enter into long-term contracts for capacity resources and associated energy. As required by the legislation, the Commission provisionally adopted rules (Chapter 316) to implement the resource plan and long-term contracting provisions of the Act.[10] The Legislature subsequently authorized the final adoption of the rules without change.[11]

The Commission hired London Economics International to assist in the preparation of the resource adequacy plan and with the solicitation and procurement of long-term contracts for capacity and energy resources. As provided for in the Commission rules, the Commission will present the Utilities and Energy Committee with an electric resource adequacy report and plan by January 31, 2008. Later in the year, the Commission will initiate a solicitation for long-term contracts consistent with the standards, policies and procedures contained in the Act and the Commission's implementing rules.

Major Cases at FERC and Other Federal Initiatives

Forward Capacity Market (FCM) Settlement

In 2006, FERC approved a contested settlement that establishes a market for generation capacity in New England and sets a schedule of payments to generators over a four-year transition period beginning December 2006. FERC had indicated that it wanted to create a locational mechanism to promote the development of more generation in the southwestern Connecticut and northeastern Massachusetts load

[8] P.L. 2005, ch. 677.

[9] Central Maine Power Company and Bangor Hydro-Electric Company are the utilities that meet the statutory definition of a large T&D utility.

[10] *Order Provisionally Adopting Rules,* Docket No. 2006-557 (Jan. 2, 2007).

[11] Resolves 2007, ch 35.

pockets, recognizing that Maine's surplus of generation resources could not always be exported from Maine due to transmission limitation.

ISO-NE had filed a proposal, known as LICAP (Locational Installed Capacity) that would have sharply increased costs for all of the New England states without requiring new generation to be built, even in those southern New England locations where it was needed. Maine, as well as every other New England state opposed the LICAP proposal. After a hearing, FERC directed the parties to engage in settlement negotiations.

The Commission worked with other states and energy companies to forge a compromise but ultimately rejected the settlement because of its impact on Maine consumers. The Commission supported the long-term market proposal which it helped to develop as part of the settlement. This long term market proposal, if properly implemented, would allow for a competitive market for new resources, including conservation and demand response resources.

However, the settlement also included transition payments for a period of time beginning in 2006. The Commission strongly opposed the transition rates approved by FERC. FERC's approval of the settlement is expected to result in rate increases of about 6% for Maine's residential electric consumers and 10% for Maine's medium and large commercial and industrial electric consumers over a four-year period. Those payments began to show up in Maine electricity bills in 2007.

FERC rejected the Commission's argument that given Maine's capacity surplus, the rate increases had not been justified for Maine consumers. The Commission sought review of FERC's decision in federal court. Briefs have been filed in the appeal. The Commission expects that the court will issue a decision on the appeal in 2008.

Installed Capacity (IC) Requirements

Another important case at FERC involves the determination of how much capacity is needed within a 12- month period to ensure the electric grid's reliability. One significant issue concerns whether states or the FERC should determine the appropriate level of reliability. The state commissions challenged FERC's authority to decide how much capacity is needed. They asserted that the Federal Power Act gives states rather than the FERC authority over resource adequacy, since ultimately retail consumers will pay the cost of increased reliability.

FERC's decision that it has sole authority to establish the IC requirement was challenged in federal court. The Commission intervened in this appeal as part of the New England Conference of Public Utility Commissions (NECPUC) and individually. In 2007, the federal court rejected FERC's explanation for its assertion of jurisdiction but did not decide the jurisdictional question; instead the court sent the case back to FERC. On remand, FERC again found that it had the authority to set the IC requirement and that determination again was appealed to federal court. The Commission is an

intervenor in that appeal, which has been consolidated with related cases involving the same jurisdictional question.

In 2007, another case involving IC requirements raised additional issues. Of significance to Maine consumers, was an issue related to the assumptions that will effect prices in the first forward capacity auction to purchase capacity for a commitment period beginning in 2010 which will take place in February 2008. The Commission protested the ISO-NE assumptions which overstate the capacity that can be exported from Maine. These assumptions could cause Maine capacity prices in the auction to be as high as those in the rest of New England. FERC approved the ISO's filing for 2007, but directed ISO-NE to begin a stakeholder process to address concerns about both the level of the IC requirement and the Maine export assumptions. The Commission is considering a request for rehearing of FERC's decision. In addition, Commission staff will participate in the stakeholder process to try to ensure that the correct assumptions are used in the second FCA.

Request for Increased Return on Equity (ROE)

In 2003, a group of New England transmission owners requested a significant increase in the return on common equity component of the regional and local transmission rates under the ISO-NE open access transmission tariff. The Commission took a lead role in developing NECPUC comments protesting the proposed increase. In October 2006, FERC issued a decision approving a lower rate but also approving the transmission owners' request for an ROE adder for new transmission construction.

The Commission, individually and as part of NECPUC, municipal utilities and other consumers had strongly objected to the new transmission adder and sought rehearing of the FERC decision. Rehearing requests are pending at FERC.

Voltage Support Cases

In December of 2006, ISO-NE filed for a rate increase in the capacity payment paid to generators that have the capability to provide voltage support. The Commission protested the rate increase because the voltage support revenue stream provides a double recovery to generators already receiving payments under the capacity settlement discussed above. Although FERC disagreed that there would be a double recovery during the capacity settlement transition period, it set the rate increase for hearing and directed the parties to try to settle the case. The Commission staff took the lead in crafting a partial settlement which reduces the proposed rate increase and allows for further rate reductions if the FERC grants the Commission's request for rehearing on the double recovery issue.

The Commission also filed a complaint related to the double recovery issue and the socialization of uplift costs for providing voltage support mainly in the Boston area. The complaint is on hold while FERC tries to work with ISO-NE and New England stakeholders to address the Commission's concerns.

Northern Maine FERC Cases

In 2007, two significant cases involving northern Maine were litigated at FERC. One involved the Northern Maine Independent System Administrator's (NMISA) proposal to impose a capacity requirement. The second involved a filing by Boralex, the entity that owns most of the generation in the northern Maine area, requesting FERC approval to continue to charge market based rates rather than traditional cost-of-service rates.

The capacity case arose from a dispute between NMISA and Integrys Energy Services (the standard offer provider in northern Maine) over whether it had an obligation to purchase capacity. The case resulted in a rate filing by NMISA which would have resulted in a substantial increase in standard offer rates. In response to the Commission's protest, FERC rejected the NMISA filing. Commission staff then worked with NMISA and northern Maine stakeholders to develop a less costly capacity methodology. The revised capacity proposal was filed at FERC in August and approved effective September 1, 2007.

In the Boralex market based rate petition, the Commission questioned whether market-based rate authority should be granted given the failed competitive market in Northern Maine. A technical conference was held at FERC in August 2007 in which the Commission participated. Other participants in the conference included Boralex and Integrys Energy Services. The Commission filed written comments following the conference. FERC has not yet issued a decision in this case by the end of 2007.

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPAct) required the Department of Energy (DOE) to undertake a nationwide study of electric transmission congestion every three years. Following the issuance of the congestion study, EPAct authorizes DOE to designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a National Interest Electric Transmission Corridor ("NIETC"). Of crucial significance, the consequence of an NIETC designation is that it gives FERC backstop siting authority over a transmission project even when the state commission finds that it is not in the public interest or the project would violate local or state environmental regulations or laws. If a state either rejects or fails to approve within a year a transmission project that is within a national corridor, FERC may override the state siting authorities and grant a permit for the siting of the line.

DOE issued its first congestion study in August 2006 and requested comments on the study. DOE categorized broad areas experiencing congestion into one of three categories which denoted DOE's evaluation of the severity of congestion within the broad area. The categories identified by DOE were: critical congestion area, congestion area of concern, and conditional congestion area. New England was designated a congestion area of concern and Maine was identified as a potential target of federal

preemption. The DOE indicated in its request for comments on the study and on possible designation of corridors that it might designate corridors in areas that fell into any of the three categories.

In 2006, the Commission filed comments both individually and as part of NECPUC and the National Association of Regulatory Commissioners (NARUC) strongly opposing the designation of corridors based on the DOE congestion study. The comments underscored the deficiencies of the congestion study, the lack of the requisite consultation with the affected states, and in New England the lack of any evidence that the state siting process had prevented the construction of any transmission project recommended by ISO-NE. DOE's designations made in October 2007 did not include any corridors in New England. This means that at present Maine's siting authority is not subject to FERC preemption.

III. MAINE RETAIL MARKET

During 2007, the retail market in most of Maine continued to show a reasonable level of competitive activity in the medium and large commercial and industrial (C&I) customer sectors. In addition, the market share profile improved. Although a large share of the market continued to be served by a set of affiliated suppliers, the market share of these companies dropped significantly in 2007 compared to prior years. The retail market continued to provide few if any options to standard offer service for residential and small commercial customers, although competition for the standard offer loads of small customers remained robust.

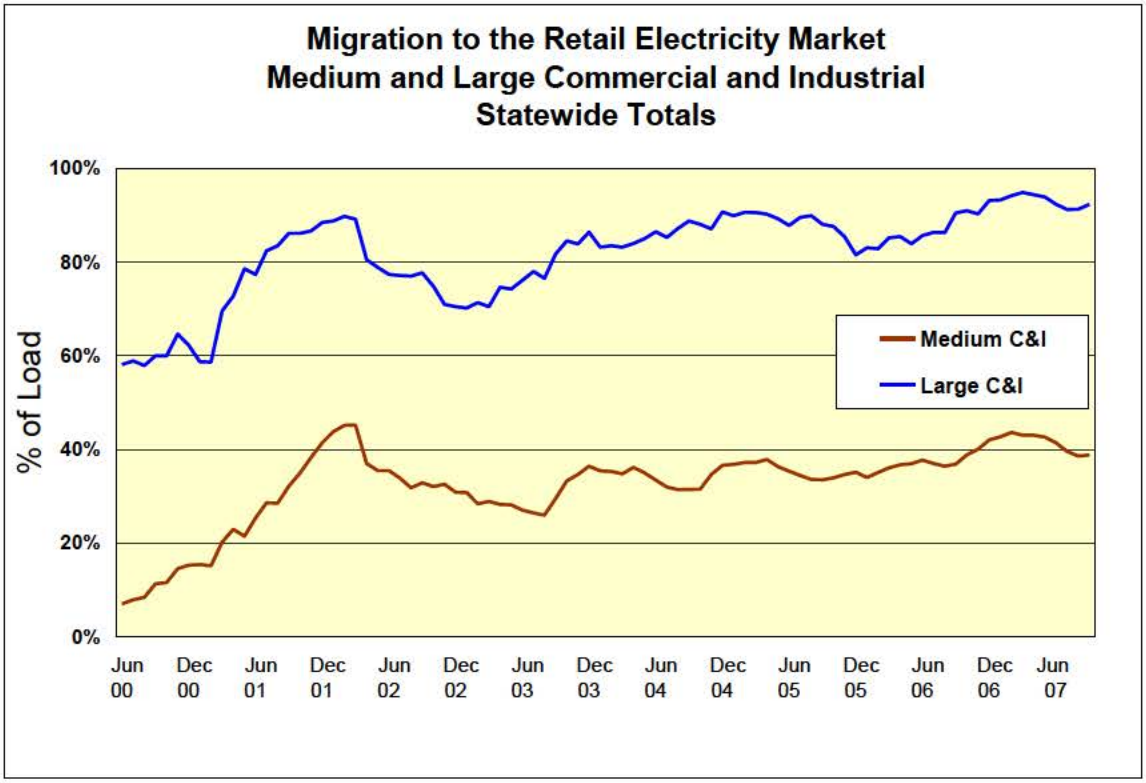
The Commission licensed 19 competitive electricity providers (CEPs) during 2007. CEPs include retail supplier, brokers and aggregators. There are 101 CEPs licensed to operate in Maine. Many of these, however, are not active in the market. A complete list of licensed CEPs is available at http://www.maine.gov/mpuc/industries/electricity/ElectricSupplier/ceplist.htm

Medium and Large C&I Sectors

Since the beginning of restructuring, many medium and large C&I customers have acquired supply directly from the retail market. Terms of service and prices are negotiated directly between customers and suppliers, or, in some cases, with the assistance of aggregators or brokers. Depending upon customer preference and supplier product offerings, prices may be fixed for multi-year terms, or, at the other end of the spectrum, prices may change hourly in accordance with real-time or near real-time wholesale markets.

Although migration to and from the competitive market 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 market once they have left the standard offer. The graph below shows migration among medium and large customers, and reflects the overall trend toward migration to the open market. Currently, almost

40% percent of the load of Maine's medium C&I customers and more than 90% of the load of the large C&I customers are served through individual retail arrangements.



Residential and Small Commercial Sectors

In 2007, there continued to be little retail market activity in the residential and small commercial sectors in Maine or other states. However, because Maine's standard offer providers are chosen through competitive bidding, residential and small commercial customers are receiving competitively-procured supply, albeit at the bulk level.

During 2007 "clean" products, featuring hydroelectric, biomass, wind, low-impact hydro generation, and "Renewable Energy Certificates (RECs)" continued to be available through residential and public sector aggregation groups. The Carbon Free Homes program was launched by the Commission in April to educate residential customers about supply options and RECs. The program's website offers customers the opportunity to learn about their home energy use, identify appropriate energy efficiency options through Efficiency Maine and other residential state energy programs, and sign up for clean energy products. This program represents the Commission's first effort to provide residential customers with a comprehensive menu of energy options. A small amount of funding allowed a public awareness media campaign through the summer of 2007. Partnerships with other Maine organizations further enabled consumer awareness of clean energy options. As of early December, the program had

achieved a moderate level of success as measured by 4,600 unique hits to the website. The program will see further expansion in 2008.

Northern Maine

Retail competition in northern Maine continued to be weak during 2007, due largely to the structural and wholesale market deficiencies described above. These deficiencies have hindered market development since retail access began in 2000.

IV. STANDARD OFFER SERVICE

Overview of 2007

During 2007, the portion of Maine's electric load that receives standard offer service remained steady at about 62%. By customer class, standard offer service supplies about 60% of the load of medium C&I customers and 6% of the load of large C&I customers in Maine. Standard offer service continues to supply virtually all residential and small commercial customers, as has been the case since retail access began.

The standard offer suppliers and prices during 2007 are set forth 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 website at http://www.maine.gov/mpuc/industries/electricity/standard_offer/standard_offer_rates.html.

Procurement Processes

CMP and BHE Residential and Small Commercial

The Commission continued to procure standard offer supply in accordance with the hedging program that began in 2005. The program relies on a "laddering" structure that allows the Commission to secure portions of the required supply at different points in time, thereby reducing customer exposure to the volatility of the wholesale market. When the hedging program began, bids were requested for one-third load segments for terms of one, two and three years. That process allowed for subsequent procurements of one-third segments annually as the initial terms expired. The 2007-2008 term includes the last of the segments initially procured in 2005.

In October 2006, the Commission issued RFPs for the one-third supply segment for the term beginning March 2007. In January, the Commission designated Florida Power & Light (FPL) as the standard offer service provider for this segment for a three-year term for both the CMP and BHE classes. Constellation Energy Commodities Groups Maine LLC (Constellation) continued as the standard offer provider for the remaining load segments. The winning bid prices for this one-third segment were 9.3 cents/ kWh on average for both CMP and BHE. When combined with the existing prices for the other two-thirds of the classes, the new bid resulted in average prices of 8.8 cents/kWh for CMP customers and 9.0 cents/kWh for BHE customers for the March 2007 through February 2008 term. This reflected an increase from the previous year's price: 5% increase for CMP customers and 3% for BHE customers. The hike reflected prevailing market conditions at the time of the various segment bids, as well as ISO-NE capacity "transition payments".[12]

In October 2007 the Commission issued RFPs for the one-third segment for the term beginning in March 2008. In this RFP, the Commission did not seek three-year terms. Instead, bids for terms of one or two years only were requested to avoid incurring a risk premium due to the uncertainty associated with full implementation of the ISO-NE

Average Standard Offer Prices in 2007

	Residential/Small Commercial		Medium C&I		Large C&I	
	Price ¢/kWh	Supplier(s)	Price ¢/kWh	Supplier(s)	Price ¢/kWh	Supplier(s)
CMP						
Jan-Feb	8.38	Constellation	13.63	FPL, Dominion	10.15	BP
Mar-May	8.79	Constellation, FPL	8.42	FPL, Dominion	9.05	Constellation
Jun-Aug	8.79	Constellation, FPL	8.94	FPL, Dominion	9.45	Constellation
Sept-Dec	8.79	Constellation, FPL	8.37	Dominion, TransCanada	8.44	FPL
BHE						
Jan-Feb	8.71	Constellation	13.66	FPL	9.80	BP
Mar-May	9.01	Constellation, FPL	8.57	FPL	10.20	Constellation
Jun-Aug	9.01	Constellation, FPL	9.07	FPL	10.44	Constellation
Sept-Dec	9.01	Constellation, FPL	7.48	Indeck, Dominion Transcanada	10.07	Constellation
MPS						
Jan-Dec	7.89	WPS	8.91	WPS	8.91	WPS

Forward Capacity Market in 2010. Suppliers submitted initial indicative proposals on November 6.

[12] The Commission's opposition to these capacity transition payments is discussed above.

CMP and BHE Medium and Large C&I

The Commission completed two solicitations for medium and large class standard offer service during 2007, and began a third in late 2007 for the term beginning March 1, 2008.

In December 2006, the Commission issued RFPs for standard offer service for the CMP and BHE medium and large classes for the six-month term beginning March 2007. Suppliers submitted indicative bid prices in January 2007 and, after negotiating and resolving non-price terms with Commission staff and utilities, suppliers submitted final binding bids later that month. After evaluating the final proposals, the Commission designated suppliers as follows:

	CMP	BHE
Medium Class	FPL 60%	FPL 100%
	Dominion 40%	
Large Class	Constellation 100%	Constellation 100%

Average prices are shown below:

	CMP	BHE
Medium Class	8.720 cents/kWh	8.827 cents/kWh
Large Class	9.255 cents/kWh	10.320 cents/kWh

The solicitation for CMP and BHE medium and large classes for the September 2007 term began when the Commission issued RFPs in May 2007. After receiving indicative bids, negotiating contract and other non-price terms, and receiving final bids, the Commission in July 2007 designated suppliers and prices as follows:

	CMP	BHE
Medium Class	Dominion 60%	Indeck 60%
	TransCanada 40%	TransCanada 20%
		Dominion 20%
Large Class	FPL 100%	Constellation 100%

Average prices are shown below:

	CMP	BHE
Medium Class	9.107 cents/kWh	8.618 cents/kWh
Large Class	9.208 cents/kWh	10.262 cents/kWh

In December 2007 the Commission issued RFPs for a six-month standard offer supply for medium and large class customers to begin in March, 2008. Bids are due in January 2008.

MPS – All Classes

As discussed above, the competitive market in northern Maine has been weak for some time. In September 2006, the Commission issued an RFP seeking standard offer service for all MPS customer classes. Because only one retail supplier bid, the Commission found the lack of competition to be unacceptable, rejected the bids and ordered MPS to supply standard offer service for an interim period.

The supplier, WPS Energy Services Inc.,[13] petitioned for reconsideration, and in December 2006 the Commission accepted the petition, designating WPS as the standard offer supplier for the MPS territory for a 26-month period beginning January 2007.[14] The Commission found that WPS' new bid terms (which were reduced from initial bid levels) would be significantly lower than prices MPS could provide through its own wholesale arrangements.

[13] WPS Energy Services has changed its name to Integrys Energy Services.

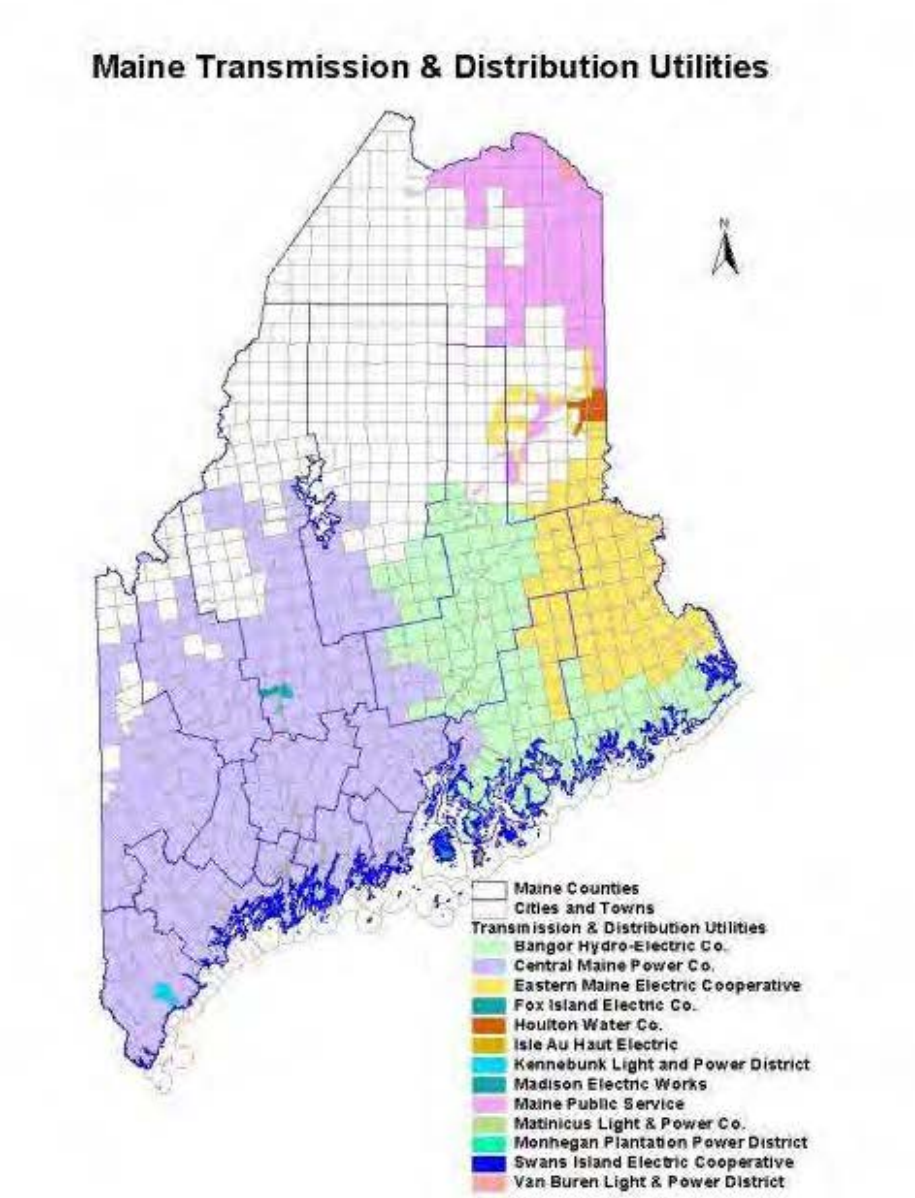
[14] The WPS bid included a "price adder" contingency to allow for then-pending changes to the northern Maine market rules that would impose new capacity requirements (and costs) on suppliers. In late 2007, the rule changes were approved by FERC. Integrys petitioned the Commission for a standard offer price increase based on the price adder contingency. On December 19, 2007, the Commission allowed an interim price increase of $0.002 per kWh. Final action on the petition is currently pending before the Commission.

Customer Class	SO Rate			SO Provider
	1/1/07- 6/30/07	7/1/07- 2/29/08	3/1/08- 2/28/09	
Residential & Small Non-Residential	7.89 ¢/kWh	8.25 ¢/kWh	8.25 ¢/kWh	WPS Energy Services, Inc.
For Medium Non-Residential	8.91¢/kWh	9.55 ¢/kWh	8.85 ¢/kWh	WPS Energy Services, Inc.
For Large Non-Residential	8.91¢/kWh	9.55 ¢/kWh	8.85 ¢/kWh	WPS Energy Services, Inc.

V. DELIVERY SERVICES AND PRICES

There are thirteen electric or transmission and distribution (T&D) utilities in Maine – three investor-owned (IOU) and ten consumer owned (COU). The three IOU's serve most of the State, and among them CMP is the largest, serving about 80% of all Maine's load in 2006. BHE and MPS served most of the remaining load, with the COUs serving, in the aggregate, a few percent.

The map below shows the geographic areas each utility serves:



The table below provides a summary of residential electricity sales and rates by utility.

RESIDENTIAL RATES IN MAINE

(Current as of 12/11/07)*

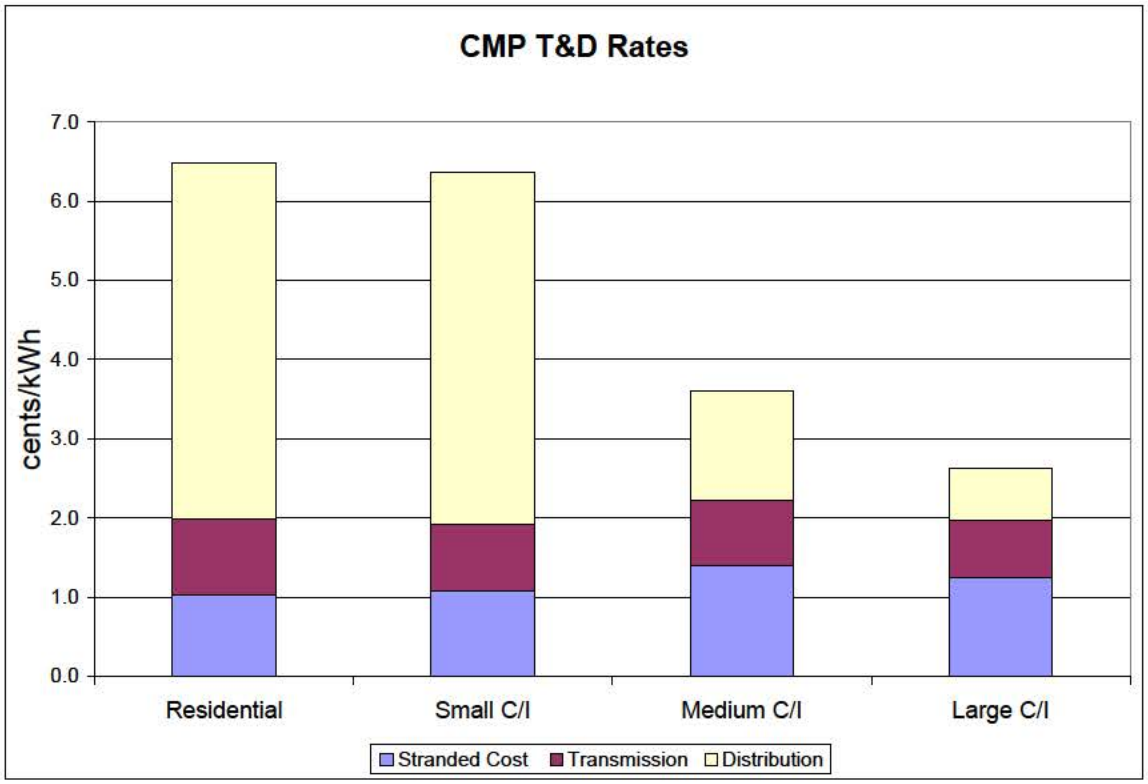
	% of T&D Load	kWh	Delivery Rate ¢/kWh	Standard Offer Rate ¢/kWh	Total Residential Rate ¢/kWh	
INVESTOR-OWNED UTILITIES						
CMP	78.8%	3,502,355,270	6.718	80	**15.51**	**¢/kWh**
BHE	13.5%	598,648,495	7.259	01	**16.26**	**¢/kWh**
MPS	4.1%	183,229,422	8.118	25	**16.36**	**¢/kWh**
COOPERATIVES & MUNICIPAL-OWNED UTILITIES						
EMEC	1 2%	51,755,685	7.675	80	**13.47**	**¢/kWh**
Houlton	0 6%	27,651,201	3.305	37	**8.67**	**¢/kWh**
Van Buren	0 2%	7,162,693	1.728	25	**9.97**	**¢/kWh**
Kennebunk Light & Power	1.1%	46,697,604	1.341	1.00	**12.34**	**¢/kWh**
MEW	0.4%	16,972,917	4.804	57	**9.37**	**¢/kWh**
Matinicus	0 0%	334,000	Exempt from Standard Offer requirements		**47.00**	**¢/kWh**
Monhegan	0 0%	294,700	Exempt from Standard Offer requirements		**55.87**	**¢/kWh**
Fox Island	0.1%	6,343,816	24.56	17.03	**41.59**	**¢/kWh**
Isle au Haut	0 0%	241,376	32.82	8.62	**41.44**	**¢/kWh**
Swans Island	0.1%	2,315,960	16.96	8.62	**25.48**	**¢/kWh**
STATE AVERAGE		4,444,003,139	6 798	77	**15.56**	**¢/kWh**

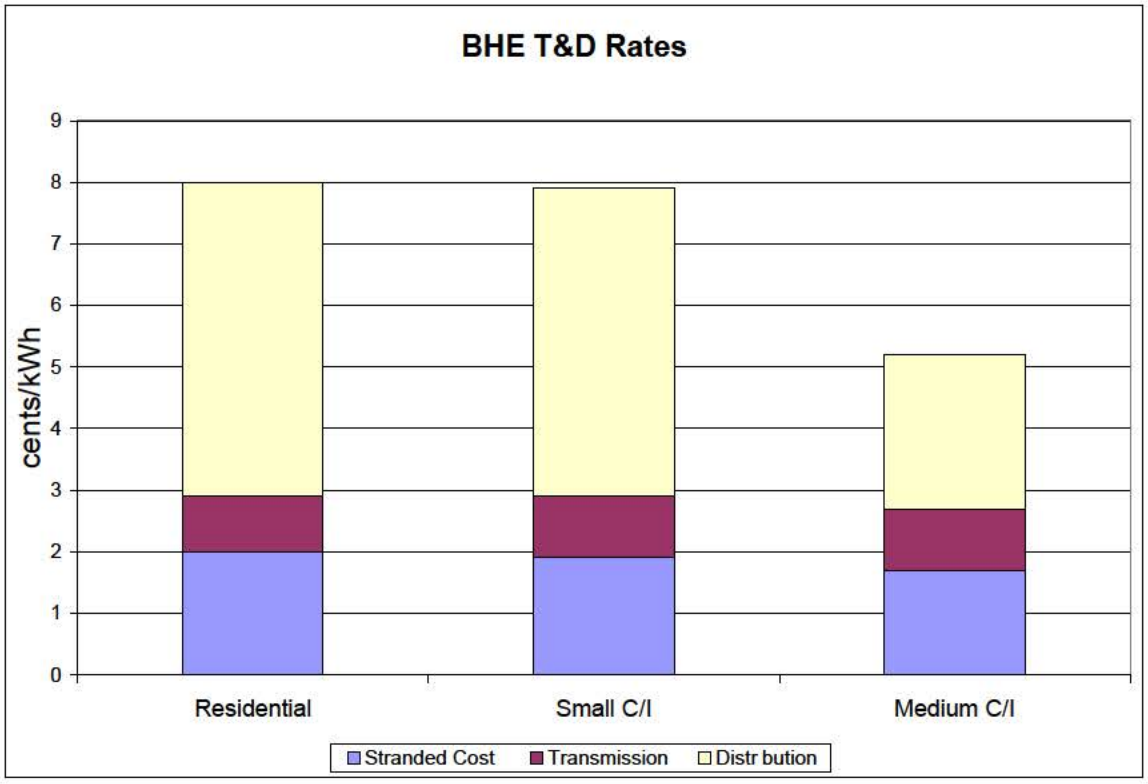
** - T&D rates based on annual reports. Standard offer rates reflect average rates as of 12/07.*

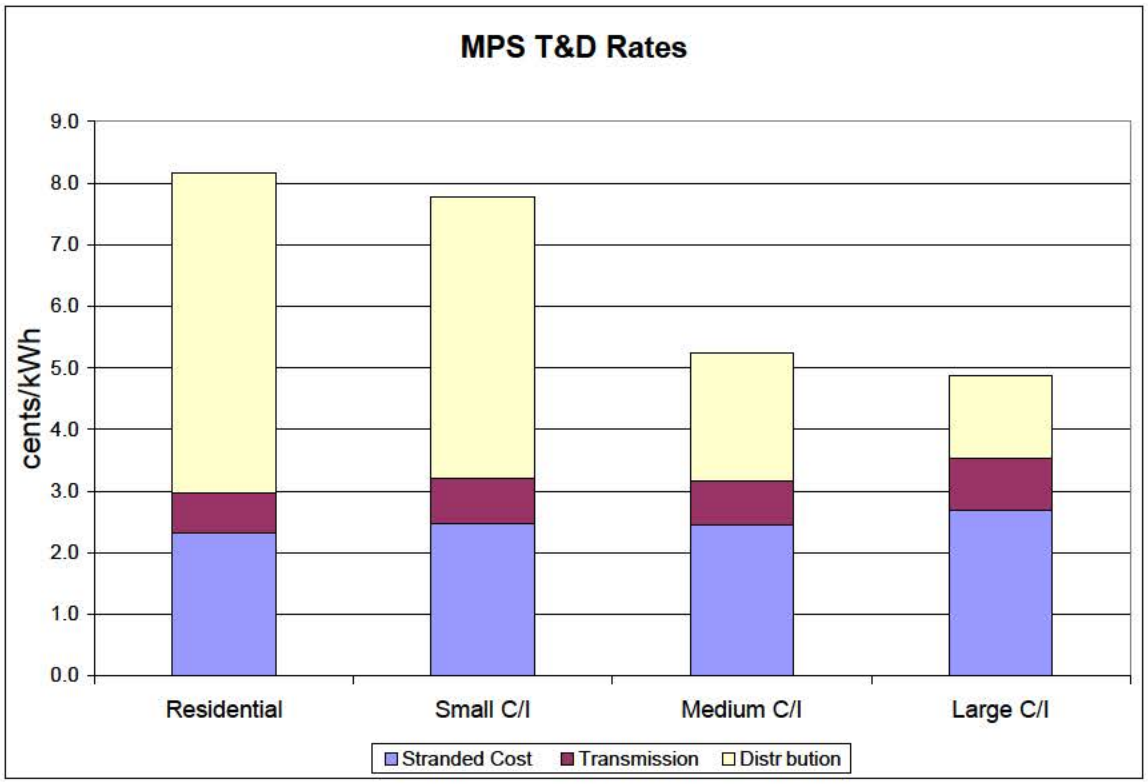
*** - Monhegan reflects 2006 rates. Updated rates not available at the time of publication.*

T&D delivery rates include three components: transmission, distribution, and stranded costs. Transmission rates cover the cost of constructing and operating the transmission system in Maine, as well as costs allocated to Maine for regional transmission facilities. Transmission rates are regulated by FERC. Distribution rates cover costs incurred by the T&D utility to construct and operate the local distribution system and are regulated by the Commission. Stranded cost rates reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring, and are also regulated by the Commission.

The following charts illustrate T&D rates for CMP, BHE and MPS:




BHE T&D Rates
cents/kWh
0
1
2
3
4
5
6
7
8
9
Residential
Small C/I
Medium C/I
Stranded Cost
Transmission
Distr bution


MPS T&D Rates
cents/kWh
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
Residential
Small C/I
Medium C/I
Large C/I
Stranded Cost
Transmission
Distr bution

Distribution

As shown above, distribution rates vary by utility and customer class. For example, residential customers typically pay more than industrial customers to reflect differences in the underlying costs to serve them, such as the fact that residential customers take service at the distribution system level while many industrial customers take service directly at the high voltage, transmission system level. During 2007, distribution rates were stable.

Transmission

Transmission rates remained relatively stable during 2007.

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 every two to three years, typically to coincide with the sale terms of the utilities' QF entitlements and may also be reconciled annually to capture difference between projected and actual expenses and revenues.

As shown below, over time stranded costs will decline to zero. The most significant changes in stranded costs occur when utilities' QF contracts expire.

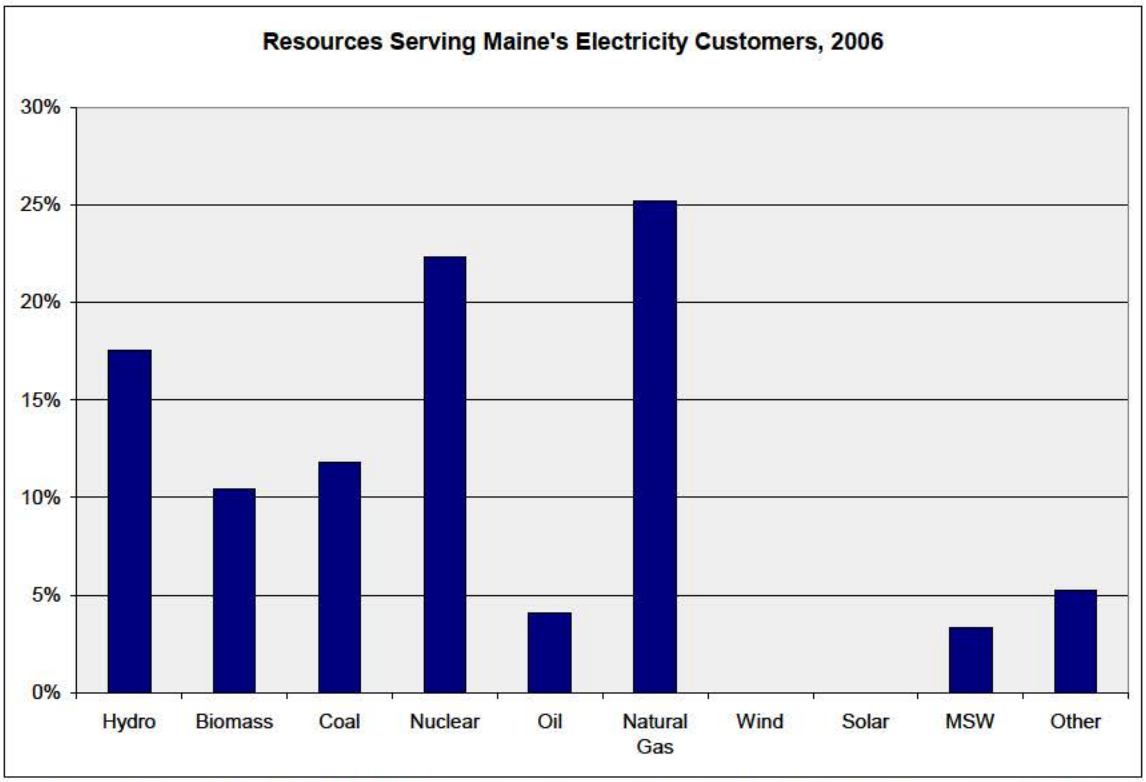
Annual Stranded Cost Projections

Stranded costs will be reestablished within the next 3 years

VI. MAINE ELECTRICITY SUPPLY RESOURCES

Resources Serving Maine Customers

The Restructuring Act established 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 defined eligible resources to be generating units whose capacity do not exceed 100 megawatts and that produce electricity from tidal, fuel cells, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste in conjunction with recycling; that qualify as small power producers under federal regulations; or that are efficient cogeneration units. Maine's electricity suppliers complied with the requirement during 2006. [15] The chart below shows the mix of resources that served Maine customers in 2006. Information regarding compliance during 2007 will be submitted in July 2008



Note: An additional 620,000 MWh is as yet unreported for 2006. The majority of this balance will be accounted for in the 2007 report year.

[15] The Commission will receive information about suppliers' 2007 resource mix and RPS compliance when suppliers file their annual reports in June 2008.

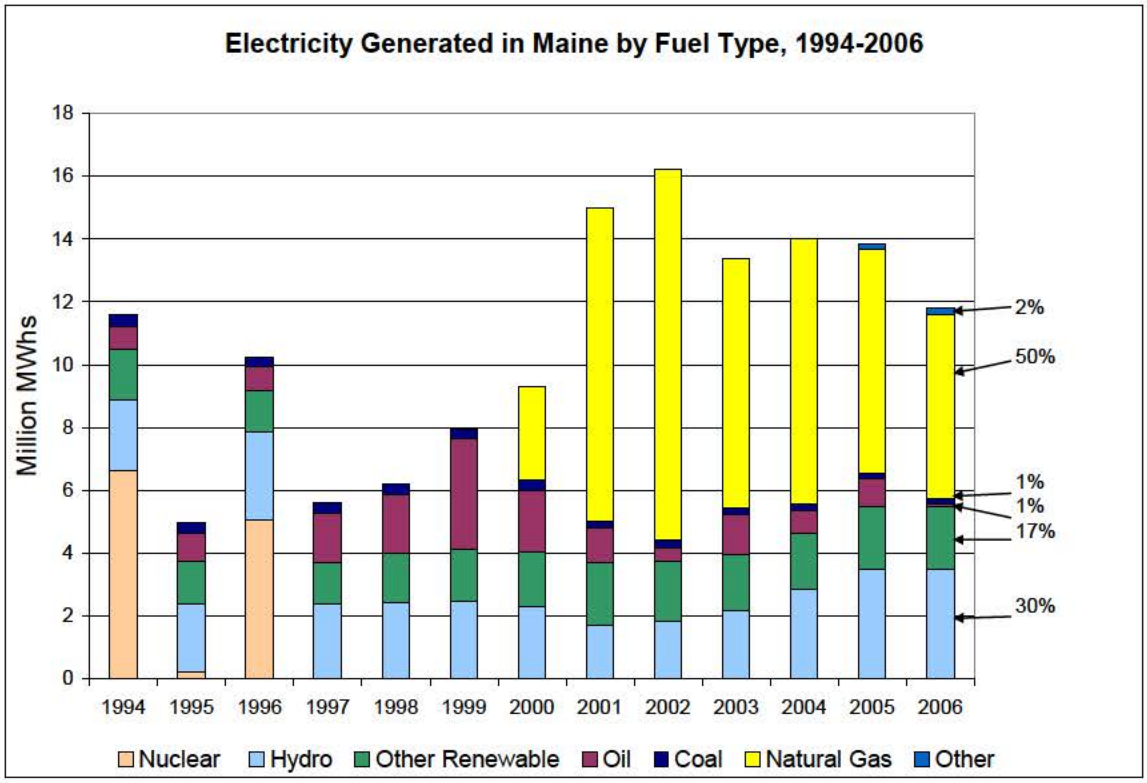
During its 2007 session, the Legislature enacted an Act To Stimulate Demand for Renewable Energy.[16] The Act adds a mandate that specified percentages of electricity that supply Maine's consumers come from "new" renewable resources, which are generally renewable facilities that have an in-service date after September 1, 2005. The percentage requirement starts at one percent in 2008 and increases in annual one percent increments to ten percent in 2017, unless the Commission suspends the requirement pursuant to the provisions of the Act. New renewable resources have a capacity limit of 100 MW, except for wind power (which has no limit), and include the following technologies or fuels: fuel cells, tidal power, solar arrays and installations, geothermal installations, hydroelectric generators that meet all state and federal fish passage requirements, or biomass generators including generators fueled by landfill gas.

The generation that fulfills the 30% eligible resource requirement and the new renewable resource requirement may come from a variety of locations. The generation that suppliers assign to load in Maine may be generated in Maine, in another New England state, or in Canada. Beginning in 2002, competitive providers in the ISO-NE territory have operated under a "tradable attribute" certificate system known as the Generation Information System (GIS). The GIS allows suppliers to trade electricity attributes (e.g., fuel source) separately from the energy commodity. Suppliers in the ISO-NE area demonstrate compliance with Maine's portfolio requirements through GIS certificates. This process reduces supplier compliance costs and allows for accurate verification.

Electricity Generated in Maine

In recent years, five electric generating plants fueled by natural gas have been built in Maine. This phenomenon is the result of both electric restructuring and the completion of new natural gas transmission facilities within the State. Publicly available information summarizes the resources used in each state to generate electricity (which may in turn be sold in other states), and shows the shift in Maine's generation mix over time. At this time, generation data is not available beyond 2006.

[16] P.L. 2007, ch. 403 (codified at 35-A M.R.S.A. § 3210(3-A)).



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 emissions 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 upon request. Labels for standard offer providers may be found on the Commission's web page at: http://www.maine.gov/mpuc/industries/electricity/standard_offer/disclosure_labels_history.html

VII. 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 2007, there were no issues associated with standards of conduct. CMP does not have a marketing affiliate. In 2002, BHE formed a marketing affiliate, Emera Energy Services, Inc. (EES), but EES does not market services in BHE's territory. MPS's marketing affiliate, Energy Atlantic, no longer serves customers in Maine.

VIII. 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 2007, concerns and questions about the merits of restructuring continued to be raised in several restructured states.

During the mid to late 1990s, many states, including Maine, responded to market conditions and FERC competitive initiatives by restructuring their electric industries to varying degrees. In most of those restructured states, competitive wholesale markets have developed, with variations responsive to individual geographic, market and political factors. On the retail level, most of the smaller customers in the restructured states rely on default or standard offer service (as in Maine) rather than directly accessing a competitive market.

A recent report to Congress by federal energy regulators and experts profiled retail competition in Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. The report characterized the results as mixed:

> In most profiled states, retail competition has not developed as expected for all customer classes. Few residential customers have switched to alternative providers. (Exceptions include Massachusetts, New York, and Texas.) In most of the profiled states, few residential customers have a wide variety of alternative suppliers and pricing options. Commercial and industrial (C&I) customers have more choices and options, but in several states large industrial customers have become increasingly dissatisfied with retail market prices. To the extent that multiple suppliers serve retail customers, prices have not decreased as expected, and the range of new options and services is often limited. At the same time, there is some evidence that alternative suppliers have offered new retail products, including "green" products that are more environmentally friendly for residential and non-residential customers and customized energy management products for large C&I customers.[17]

Price caps imposed by some states at the outset of restructuring efforts a decade ago have begun to be lifted over the last two years. As a result, consumers of all classes in those states have been hit by dramatic price increases and they have demanded legislative response. Several states are responding by seeking greater regulatory involvement in the energy marketplace.

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[17] Electric Energy Market Competition Task Force, "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy" available at http://www.usda.gov/rus/electric/competition/index.htm

Movement to "re-regulate" or modify restructured markets gained momentum toward the end of 2007. In Maryland, for instance, utility regulators in December called for quick intervention to avert a capacity crisis and rolling blackouts by 2010. In a report submitted to the Maryland Commissioners in November, 2007, a group of consultants surveyed the restructuring landscape in the U.S.:

> [A] number of states have (sic) taken tentative steps toward re-regulation, but no state has yet blazed an incontrovertible path from deregulation back to the vertically integrated model that was the norm for almost all of the twentieth century. Even in the face of unsettling rate shocks and disappointing development of new generation resources, states have been cautious about such a radical course shift after less than a decade of deregulation experience. Moreover, the stimuli that led to a wave of deregulations have not disappeared. Customers remain averse to assuming large capital costs for generation facilities that may turn out to have been unnecessary or too expensive. Utilities have not demonstrated dramatically improved management that is likely to match efficiency gains achieved by many merchant generators. Regulators have not yet implemented formulas that instill incentives for productivity and innovation comparable to those in competitive markets.[18]

California's energy crisis in 2001 triggered the first wave of retreat from restructuring. Eight states have now repealed or delayed their restructuring laws. By 2007, Ohio and Pennsylvania, while moving toward the competitive market, still had price caps in place that insulated consumers from the risks and benefits of competition.

Currently, electricity is delivered under a restructured market in Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, Michigan, New Hampshire, New Jersey, New York, Rhode Island, and Texas. Some of those states are now considering significant changes, including modified return to cost-of-service regulation, the reconstitution of vertically integrated generation and distribution companies, and institution of long-term contract requirements. While the experience of states where restructuring is currently viewed as problematic receive the bulk of public attention, it should be noted that several states, including Massachusetts, New York, and Texas, are moving forward relatively smoothly under restructuring legislation.

All of the New England states, except Vermont, restructured their electricity markets a decade ago. In contrast to many of the restructured states where significant changes are in motion, the New England states by and large are not proposing or enacting an overhaul. Reports by industry and other analysts find that fuel-adjusted wholesale prices in New England have dropped substantially since restructuring was instituted, while investments in generation and capacity continued at a reasonable pace without putting consumers at risk for failures or stranded costs. In a 2005 report, ISO-

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[2]Kaye Scholer LLP, Levitan & Associates, Inc., and Semcas Consulting Associates, "State Analysis and Survey on Restructuring and Reregulation," available at http://www.psc.state.md.us/psc/Reports/KayeScholer_State%20Analysis%20and%20Survey%20on%20Restructuring%20and%20Re-Regulation%20_11.30.07.pdf

NE found that efficiencies created by competition reduced wholesale market costs (again, fuel-adjusted) by $700 million a year.

> Competitive markets have created incentives to improve the operation, utilization, efficiency, and overall performance of existing generation and transmission facilities. For example, plant owners responding to wholesale prices are motivated to keep their plants well maintained, available in times of greatest need, and running when demand is highest. This increase in "generator availability" has reduced the need to build additional plants and lowered wholesale market costs.
>
> In addition, the investment in new, efficient generation has resulted in a reduction in the use of older, less efficient and more polluting power plants, delivering environmental as well as economic benefits to consumers. Specifically, the move to more efficient gas-fired generators has decreased the use of the region's oil and older gas power plants and is estimated to have reduced annual carbon dioxide emissions by 6%, nitrogen oxide emissions by 32%, and sulfur oxide emissions by 48% from these units from 2000 to 2004.[19]

There is no consensus on whether recent price increases are primarily the result of the introduction of competitive markets, or whether they merely reflect general price conditions in the energy sector. Margaret Schowalter of Power in the Public Interest, for example, argues the former in "Price Trends for Industrial Electricity, Deregulated vs. Regulated States,"[20] while Peter Cramton and Steven Stoft tend to argue the latter in "Uniform Price Auctions in Electricity Markets."[21]

Select State Highlights

- MARYLAND: Price caps ended in 2006, hitting ratepayers with price increases of up to 70 percent over two years. In its December 2007 interim report to the state Legislature, Maryland's Public Service Commission cited "structural unfairness" in the state's energy markets, concluded that the state faced a capacity and reliability crisis that would not be solved by market forces, and called for regulatory intervention in the "immediate future." Proposed solutions include long-term supply contracts and greater presence in FERC proceedings.
- NEW YORK: A 2006 staff report by New York's Public Service Department found a broad level of success in the transition to competition under several metrics,

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[19] ISO-NE, "Progress of New England's Restructured Electric Industry and Competitive Markets," available at http://www.iso-ne.com/pubs/whtpprs/rto_paper.pdf

[20] Margaret Schowalter, "Price Trends for Industrial Electricity, Deregulated vs. Regulated States, available at http://www.ppinet.org/PDFs/PPI-rp-INDjul07data-nov07.pdf

[21] Peter Cramton and Steven Stoft, "Uniform Price Auctions in Electricity Market," available at http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-clearing-price-markets.pdf

including price, market robustness, investment in generation and transmission infrastructure, demand side response programs, migration to competitive supply, number of ESCOs, and generator performance. The total electric price for a typical residential retail customer in New York, including supply and delivery charges, dropped by an average of approximately 16 percent between 1996 and 2004.

- DELAWARE: After price caps ended in 2005, consumer electricity rates rose 60 percent and more. Lawmakers in 2005 gave the state's regulators more market oversight, requiring existing distribution utilities to conduct least-cost planning, to perform cost-benefit analyses for the potential acquisition of existing or new generation capacity, and to develop demand reduction incentives. The new law also gives significant consideration to supply that provides environmental benefits.
- TEXAS: Most of the transmission grid in Texas does not connect to other states, leaving the state's competitive marketplace free of oversight by FERC. In this unique situation, the state has seen substantial migration to competitive supply, which typically discounts standard offer rates by 10 percent. As of 2006, more than 56 percent of the state's electricity was supplied by a competitive supplier, rather than an incumbent. In 2006, Texas regulators adopted new rules aimed at forestalling market power abuses. In March 2007, The Texas Public Utilities Commission staff proposed $210 million in fines against TXU for alleged abuse of market power.
- VIRGINIA: In April 2007, Virginia's Governor signed a new law which will substantially limit consumers' ability to buy electricity on the competitive market. The measure ends rates caps two years earlier than planned, in 2009, and establishes a new mechanism for regulating the rates of investor-owned electric utilities. The new regulatory structure will allow transmission and distribution utilities to own generation, and gives consideration to both rate-of-return and performance-based factors in determining rates.
- MICHIGAN: A January 2007 report by Michigan's Public Service Commission cited the "costly and volatile" wholesale market, and called for construction of new, utility-owned baseload generation, under either traditional cost-based "used and useful" regulation or an alternative, integrated resource planning model.
- OHIO: Ohio's Governor proposed comprehensive energy legislation that the state Senate passed unanimously in November, 2007: The bill would require electric utilities to prove that a competitive market exists by 2009 before market-based pricing can go forward. If regulators did not find competition existed, they would set rates under a cost-based regime. The bill was pending in Ohio's House of Representatives at the time of this writing.
- MASSACHUSETTS: In 2005, a transitional period that included mandated standard offer supply expired, moving the state to a substantially restructured marketplace. Recent statistics reported by the state Department of Public Utilities show that more than half of electricity supply is provided by competitive suppliers – although by far the largest proportion of that supply is purchased by industrial consumers.
- NEW HAMPSHIRE: The state does not track migration statistics needed to assess the level of participation in the competitive market. One analysis by an energy

industry group, the New England Alliance, however, did find that New Hampshire electricity prices (inflation-adjusted) had dropped post-restructuring – to an average of 12.5 cents per kWh between 1998 and 2005, while New Hampshire consumers saved nearly $1 billion over electricity prices that would have occurred had restructuring not been in place.[22]

- CONNECTICUT: In February 2007, Connecticut's Governor established a task force to study generation procurement for standard offer service and last resort service. The task force is expected to make recommendations to reduce or control electricity generation prices. In 2006, utilities were required to hold multiple auctions for standard offer supply, and the state Department of Public Utilities Control was empowered to issue RFPs for capacity contracts.
- RHODE ISLAND: In 2006, the Rhode Island's Legislature responded to less-than-robust development of a competitive supply market by delaying the end of standard offer service from 2009 until 2020. The law also established a requirement for utilities to file annual plans that provide for "least-cost" procurement, whether from energy efficiency, cogeneration, renewable energy, or conventional energy sources.

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