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PUBLIC UTILITIES COMMISSION
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December 30, 1997

Honorable Richard J. Carey, Senate Chair
Honorable Kyle W. Jones, House Chair
Joint Standing Committee on Utilities & Energy
State House Station #115
Augusta, Maine 04333

Re: Electric Industry Restructuring Report

Dear Sen. Carey and Rep. Jones:

In the last session, the Legislature enacted P.L. 1997, Ch. 316, An Act to Restructure the State's Electric Industry. As codified, 35-A M.R.S.A. § 3217 requires the Commission to submit an annual report to the Utilities & Energy Committee describing the Commission's activities in implementing the statute and describing restructuring activities in other states. That report is attached.

We hope that we will have an opportunity in the upcoming session to discuss with the Committee in more detail the report and the status of electric restructuring generally. Until then, if you have any questions regarding the report or any other utility matter, please don't hesitate to contact the Commission.

Sincerely,

Thomas L. Welch, Chairman
William M. Nugent, Commissioner
Heather F.Hunt, Commissioner
Maine Public Utilities Commission

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Report on the Implementation of P.L. 1997, Ch. 316 "An to Restructure the State's Electric Industry"

The following is an outline of the Commission's electric restructuring activities since the enactment of P.L. 1997, Ch. 316. A synopsis of restructuring activities in other states is included in Appendix 1. Also attached as Appendix 2 is a calendar of future restructuring proceedings.

I. RULEMAKINGS

- Standard Offer (35-A M.R.S.A. § 3212). On August 19, 1997, the Commission initiated a Notice of Inquiry to obtain comments and proposals from interested parties on the terms and conditions for standard offer service and the selection process of standard offer service providers. On September 30, 1997, the Commission issued a notice of rulemaking and a proposed rule on standard offer terms and conditions and on a bid process. The standard offer rule has been designated as a major substantive rule. The Commission will provisionally adopt the rule and submit it to the Legislature for review by February 15, 1998.
- Customer Education (35-A M.R.S.A. § 3213(2)). As required by the Act, the Commission established the Consumer Education Advisory Board consisting of 15 members. The Advisory Board met on several occasions over the summer and fall to formulate its recommendations to the Commission. On October 27, 1997, the Advisory Board submitted its recommendations to the

Commission regarding a consumer education program. On November 3, 1997, the Commission issued a notice of rulemaking and proposed rule on a customer education program. The proposed rule includes most of the Advisory's Board recommendations, including a program budget of $1.6 million. The customer education rule has been designated as a major substantive rule. The Commission will provisionally adopt the rule and submit it for Legislative review no later than February 1, 1998.

- Qualifying Facility Contracts (P.L. ch.316, §§ 5, 6, 7, 8, 9). The Commission initiated a Notice of Inquiry on August 6, 1997 regarding the impacts of electric restructuring on contracts between qualifying facilities and electric utilities. The Commission sought comments on methodologies for establishing long-term avoided costs and short-term as-available energy rates for existing QF contracts and on how its current regulations should be modified in light of industry restructuring. On October 31, 1997, the Commission issued a notice of rulemaking and proposed rule that contains alternative proposals for establishing long-term avoided costs and short-term energy rates, as well as alternative approaches for net energy billing for customers with small generating facilities after the initiation of retail access. These rules have been designated routine technical rules; the Commission plans to adopt the final rules by March 1, 1998.
- Bill Unbundling (35-A M.R.S.A. § 3213(1)). The Commission issued a Notice of Inquiry on October 31, 1997, seeking comments on how bills should be

unbundled to separately state generation service charges from T&D charges and requesting comments on whether other cost elements should be unbundled. The Notice of Inquiry requires utilities to file bill unbundling proposals by January 31, 1998. The Commission anticipates initiating a rulemaking proceeding by March 1998. The bill unbundling rules have been designated as routine technical rules; the Commission will adopt the final rules by July 1, 1998. As required by the statute, utilities will issue unbundled bills beginning January 1999.

- Utility Employee Transition Benefits (35-A M.R.S.A. §3216). The Commission issued a Notice of Inquiry on November 20, 1997 seeking comments on how it should implement the employee transition benefits section of the restructuring statute. The Commission anticipates initiating a rulemaking proceeding by March 1998. The employee transition benefits rules have been designated routine technical rules; the Commission plans to adopt final rules by August 1998.
- Conservation Programs (35-A M.R.S.A. §3211). The Commission issued a Notice of Inquiry on November 25, 1997 regarding the implementation of energy conservation programs after industry restructuring. The Commission sought comments on the appropriate level of funding, type of programs and the process for periodic competitive bidding. The Commission anticipates initiating a rulemaking on these matters by April 1998. These conservation program rules have been designated major substantive rules. The

Commission anticipates provisionally adopting the rules by September 1998 and submitting the rules for Legislative review in the following legislative session.

- Load Profiling. The Commission issued a Notice of Inquiry on December 2, 1997 seeking comments on whether there should be rules or a process for determining the load profiles of customers without sophisticated hourly metering. Such a process may be necessary to allow for an efficient and workable market for smaller customers. Comments from interested persons are due January 22, 1998. After reviewing the comments, the Commission will determine the future course of proceedings.

II. ADJUDICATIONS

- Central Maine Power Company Divestiture Plan (35-A M.R.S.A. §3204). CMP filed its proposed divestiture plan on August 11, 1997. The details of the plan were adjudicated. On December 24, 1997, the Commission issued an Order approving the plan but required CMP to continue to evaluate alternative means of divestiture when bids are received. CMP must also file a market power analysis when it seeks final approval of its sale of generating assets.

- Maine Public Service Company Divestiture Plan (35-A M.R.S.A. § 3204). MPS filed its divestiture plan on September 22, 1997. The plan is currently being adjudicated. The Commission's schedule calls for an order on the plan to be issued by January 30, 1998.

- Central Maine Power Company's Stranded Cost and T&D Ratemaking (35-A M.R.S.A. §§ 3208, 3209). The Commission initiated its investigation of CMP's stranded costs, T&D revenue requirement and rate design on September 30, 1997. The proceeding is currently being adjudicated. The schedule calls for conclusion of the case in November 1998.

III. LEGISLATIVE STUDIES

- Low Income Assistance Program (P.L. 1997 Ch. 316, § 10). The Commission issued a Notice of Inquiry on October 7, 1997, soliciting public comment on legislation that would fund assistance for low-income electric consumers through tax revenues. After reviewing the comments, the Commission and the State Planning Office prepared draft legislation that would fund low-income assistance through the General Fund. On December 12, 1997, the Commission solicited public comment on the draft legislation; comments are due on December 24, 1997. On December 31, 1997, after reviewing additional comments, the Commission and the State Planning Office will provide to the Utilities & Energy Committee draft legislation for the funding of low-income electric assistance.

- Market Power Study (P.L. 1997 ch.447, § B-1). The Commission and the Department of Attorney General have been conducting a study of market power issues related to electric industry restructuring since August 1997. The Commission and Attorney General have obtained information from utilities and other sources necessary to analyze market power issues. The

Commission and the Department of Attorney General will file an interim report describing the status of the market power study no later than February 1, 1998. The Department and the Commission will provide its final report of findings and recommendations no later than December 1, 1998.

IV. REGIONAL ACTIVITIES

The Commission has continued to monitor and participate in matters relating to the developing wholesale electricity markets in New England region. The Commission is working closely with the other New England states to ensure an efficient transition to a competitive wholesale market. In the context of FERC's ongoing review of NEPOOL and the creation of the ISO, the Commission, in conjunction with the other New England states, has participated in discussions with NEPOOL and the ISO regarding specific market mechanisms, system reliability, market power concerns, and ISO independence and self-funding. For the most part, these discussions have been fruitful, avoiding the need for major litigation at the FERC.

V. PROPOSED STATUTORY CHANGES

Upon review of the Restructuring Act, the Commission proposes that the Utilities & Energy Committee consider adoption of the following amendments to the Act.

1. Selection of Standard Offer Provider

Section 3212, subsection 2, requires the Commission to select standard offer providers by July 1, 1999. The Commission proposes that this date be moved back to December 1, 1999. Delaying the standard offer provider selection will provide greater flexibility while permitting sufficient lead time for the winning bidder to prepare to assume the standard offer obligations. We anticipate that if this proposal is adopted, the Commission will still review bids well before December 1, 1999. The additional time will permit the Commission to clarify bids or to solicit additional bids, if that action appears desirable.

2. Default of Standard Offer Provider

The Act directs the Commission to consider methods of protecting against a standard offer provider's failure to provide service (35-A M.R.S.A. § 3212, sub-1). Although the Commission is considering options with regard to a standard offer provider's default, if such an event occurs, it will be necessary to ensure that service remains uninterrupted. The local transmission and distribution utility appears to be ideally suited for that role. For that reason, the Commission proposes that the Legislature clarify that such activity does not violate the prohibition against transmission and distribution utilities marketing.

3. Review and Award of Standard Offer Provider Contract

Section 3212 requires the Commission to "administer" a bid process to select a standard offer provider and to "review" and "select" the standard offer providers. The Commission understands this language to require it to adopt a bidding process in our rules and to review and select the actual providers pursuant to that process. Notwithstanding the apparent clarity of this language, other statutory provisions may create some ambiguity over the process to be used in selecting a standard offer provider. Title 5, section 1831 (governing state agency contracts not subject to the State Purchasing Office), requires a state agency to have adopted rules that govern "purchasing services or awarding grants or contracts" no later than January 1, 1991. Obviously, the Commission cannot meet that deadline in this instance. Since the award of a standard offer contract does not involve the state's purchase of electricity, the Commission proposes that the award of the standard offer provider contract be exempt from Title 5, chapter 155.

4. Consumer Education Funding

The Consumer Education Advisory Board recommended that the Commission oversee an extensive consumer education effort to advise electric consumers of the changes occurring as a result of electric industry restructuring. The Advisory Board recommended a budget of $1,600,000 for this purpose. The Commission is proposing that the Legislature authorize the imposition of a special assessment in this amount to fund the consumer education program.

VI. CONCLUSION

The activities described above represent only the beginning of the Commission's restructuring efforts. Calendar year 1998 promises to be extremely busy as the Commission addresses several major aspects of restructuring. Maine should also benefit from the initial experiences in other states that are progressing on even more ambitious time schedules to implement electric industry restructuring. The Commission will endeavor to keep the members of the Utilities & Energy Committee well informed on our progress. The First Regular Session of the 119th Legislature in 1999 should be very busy for the Utilities & Energy Committee as several major substantive rules will be ready for Legislative review in addition to the list of amendments required to conform Title 35-A to the provisions of the restructuring act.

RESTRUCTURING ACTIVITIES IN OTHER STATES

This appendix provides a survey of electric restructuring activities in other states. This survey has two parts:

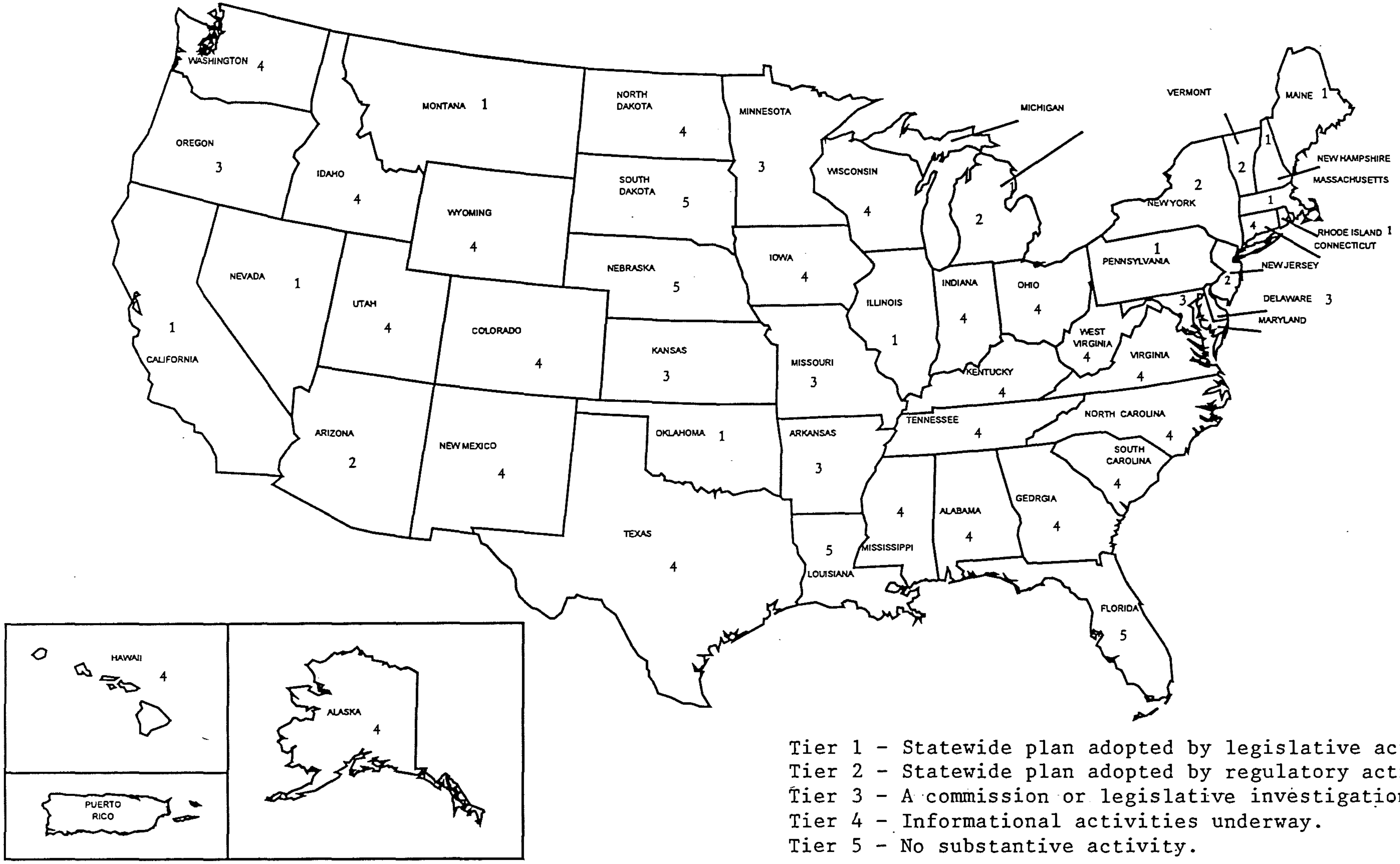
- A table and a map that provide a snap-shot view of restructuring activities in the United States. The states have been divided into five categories as follows:

  - Tier 1: A statewide restructuring plan has been adopted by legislative action.
  - Tier 2: A statewide restructuring plan has been adopted by regulatory action.
  - Tier 3: A commission or legislative investigation is underway that appears likely to lead to the adoption of a restructuring plan.
  - Tier 4: Informational or fact-finding activities are underway.
  - Tier 5: No substantive activity is underway or a decision has been made that no action is necessary.

- A state-by-state summary of commission and legislative activies. Activities in the other New England states are presented first, followed by the other states.

TABLE 1: CLASSIFICATION OF STATE RESTRUCTURING ACTIVITIES

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
California	Arizona	Arkansas	Alabama	Dist. of Colum.
Illinois	Michigan	Delaware	Alaska	Florida
Maine	New Jersey	Kansas	Colorado	Louisiana
Massachusetts	New York	Maryland	Connecticut	Nebraska
Montana	Vermont	Minnesota	Georgia	South Dakota
Nevada		Missouri	Hawaii	
New Hampshire		Oregon	Idaho	
Oklahoma			Indiana	
Pennsylvania			Iowa	
Rhode Island			Kentucky	
			Mississippi	
			New Mexico	
			N. Carolina	
			North Dakota	
			Ohio	
			S. Carolina	
			Tennessee	
			Texas	
			Utah	
			Virginia	
			Washington	
			West Virginia	
			Wisconsin	
			Wyoming	



Tier 1 - Statewide plan adopted by legislative action.
Tier 2 - Statewide plan adopted by regulatory action.
Tier 3 - A commission or legislative investigation is underway.
Tier 4 - Informational activities underway.
Tier 5 - No substantive activity.

ACTIVITIES IN OTHER NEW ENGLAND STATES

Connecticut

- Comprehensive electric restructuring legislation was not brought to a floor vote. Issues included the proposed 10 percent rate reduction, securitization, and stranded cost recovery for nuclear plants. Stakeholders are expected to discuss issues further in coming months and legislative hearings are expected to begin in February 1998.

- Northeast Utilities newly appointed Chairman stated in early December 1997 that Northeast Utilities now supports immediate electricity deregulation in Connecticut and is ready to divest its generation assets as part of the process.

- The Connecticut Department of Public Utility Control (DPUC) is continuing with its unbundling proceeding, which is addressing how costs should be assigned between generation, transmission, and distribution. A decision is expected in late 1997.

Massachusetts

- The Massachusetts legislature passed major electric restructuring legislation in November 1997.

New Hampshire

- New Hampshire Governor Jeanne Shaheen has offered a proposal which, if accepted, would break the deadlock caused by a utility lawsuit blocking the state's restructuring plan. The utility lawsuit relates primarily to the utility's objections to the state's treatment of stranded costs. Under Governor Shaheen proposal, PSNH would receive 90 percent stranded cost recovery in exchange for an on-time start to retail competition in January. PSNH and the Governor are still far apart but are continuing to negotiate.

- On November 13, 1997, the New Hampshire Electric Cooperative made a $400 million cash offer for PSNH's transmission and distribution assets and $1 billion for stranded asset recovery. The $1,400 million offer does not assume PSNH's debt of $687 million. PSNH has rejected the offer, stating that it falls short by about $1 billion in meeting PSNH's financial obligations.

- Legislation approved in New Hampshire requires retail wheeling as early as January 1, 1998 and no later than June 30, 1998. On December 15, 1997, the New Hampshire Public Utilities Commission shifted its target date for retail choice to July 1, 1998 because of delays resulting from litigation of stranded cost recovery.

Rhode Island

- Retail competition began on July 1, 1997 for large industrial customers. Many eligible customers have contracted for competitive generation service.

- Legislation approved in Rhode Island requires retail wheeling by July 1, 1998 and requires the restructuring of the electric industry. In June 1997, the legislature amended its restructuring law, including permitting securitization of stranded costs.

- The legislation sets a nonbypassable stranded cost transition charge of 2.8 cents per kWh beginning when retail access begins, through the end of 2000, when it will be replaced by a PUC-determined stranded cost recovery charge. Most categories of stranded costs would be recovered by the end of 2009.

Vermont

- The Vermont Senate passed electric restructuring legislation, which included a 50/50 division of stranded cost recovery between ratepayers and shareholders.

- The Vermont House shelved the bill until 1998 and plans to "start from scratch" on electric restructuring issues. The House formed a special 10-member committee on Utility Regulatory Reform. The committee is currently reviewing a bill that would require a performance-based ratemaking approach but that would not establish a date certain for direct access.

- The Vermont Public Service Board's restructuring plan would require that retail competition begin in January 1998. Given that the legislature has not acted, the PSC intends to continue with its activities but retail competition is not expected to begin for some time in the future.

ACTIVITIES IN OTHER STATES

Alabama

- Legislation was enacted that authorizes the PSC or the courts to review contracts for service to departing customers by new suppliers and to determine whether those contracts are in the public interest. If the PSC or the court approves the contract, it must require the departing customer to compensate its former supplier for stranded costs (*i.e.* "exit fees").

- This legislation is being appealed in federal court.

Alaska

- Two electric restructuring bills have been introduced in the Alaska legislature.

- The Alaska Public Utility Commission has recently created a generic docket to explore electric restructuring issues. The PUC is expected to pursue a "go slow" approach.

Arizona

- The Arizona Corporation Commission (ACC)'s electric restructuring rules call for full retail choice by 2003; under the phase-in plan, 20% of customers would have choice by 1999, 50% by 2001, and 100% by 2003. Arizona Public Service Company, Tucson Electric Power, cooperative utilities, and others have filed court challenges.

- The ACC is conducting workshops and formal hearings to address many of the final plan's details.

- A legislative subcommittee is considering electric restructuring issues but is expected to recommend against legislation that would duplicate the ACC's restructuring rules.

Arkansas

- On October 7, 1997, Arkansas stakeholders signed a settlement agreement with Entergy Corporation that would begin the process of mitigating stranded costs and would set the state down the road to retail competition. If the settlement is approved by the Arizona Public Service Commission there would be a hearing on restructuring during 1998.

- The Arkansas legislature has set up an interim committee to study retail competition.

California

- The Legislature unanimously approved and the governor signed into law comprehensive restructuring that affirms the PUC's restructuring policy decision and timetable as state energy policy. The law achieves at least a 10% reduction for residential and small commercial customers starting in 1998. One feature of the legislation authorizes the California Infrastructure and Economic Development Bank to issue "rate reduction bonds," which would be used to acquire transition property (*i.e.* stranded assets).

- Under the restructuring plan, direct access was to begin in January 1998 and most stranded costs are to be recovered by 2005. On December 22, 1997, the California Independent System Operator and Power Exchange announced that direct access retail competition would be delayed for several months because the computer software and hardware that will run the system are not fully functioning.

Colorado

- Numerous bills dealing with electric competition were introduced during the 1997 Colorado legislative session but all failed to receive enough support for passage. In May 1997, a Colorado legislative committee rejected a bill to study electric restructuring because of the bill's expense.

- The Public Utilities Commission inquiry on electric restructuring issues has been inactive in recent months.

Delaware

- The Delaware legislature adopted HR 36, which urges the Delaware Public Service Commission (DPSC) to complete its restructuring proceeding and submit its recommendations to the House by January 31, 1998. The DPSC is expected to meet this schedule.

- District of Columbia

- In July 1997, the D.C. Public Service Commission (DCPSC) received comments from parties in its restructuring inquiry. The DCPSC is expected to move slowly on electric restructuring issues.

- The Commission has asked for comments on certain electric restructuring issues in its review of the proposed merger between Potomac Electric Power Company (PEPCO) and Baltimore Gas & Electric (BG&E). Hearings in this proceeding have concluded.

Florida

- The legislature has reportedly blocked Florida Public Service Commission efforts to explore retail competition.

Georgia

- The Public Service Commission staff has completed a series of workshops on electric restructuring and is expected to make recommendations to the PSC on next steps.

Hawaii

- The Public Utilities Commission has begun collaborative discussions on electric restructuring issues.

Idaho

- A special legislative committee, which was established earlier this year, has begun a two-year review of electric restructuring. The committee began by reviewing the comprehensive restructuring legislation that was enacted in Montana. Several bills have been referred to the committee.

- The legislature has directed the Idaho Public Utilities Commission to study unbundling utility costs and the potential effects of electric restructuring on Idaho residents.

- In 1996, the PUC had concluded a restructuring investigation that found that deregulation or opening up Idaho's distribution system "is not feasible or desirable at this time."

Illinois

- The Illinois Senate passed comprehensive electric restructuring legislation on October 30, 1997 and the Illinois House followed suit, with some modifications, on November 14, 1997. Illinois Governor Edgar is expected to sign the bill by year-end 1997.

- For industrial customers, retail competition would begin in 1998. For residential customers, retail competition would begin in 2002.

- For "high-cost" electric utilities, the legislation requires a 15 percent rate reduction in August 1998 and a further 5 percent rate cut in 2002.

Indiana

- The Senate sent an electric restructuring bill to a study committee. The study bill instructs the existing Regulatory Flexibility committee to study electric restructuring and provide recommendations to the legislative council.

Iowa

- The Iowa Utilities Board (IUB) recommends a "go slow" approach on electric restructuring but is preparing a retail competition model so that the state will have a substantially complete plan in place for possible future adoption.

- Several electric restructuring bills will carry over to the next legislative session.

Kansas

- The Kansas legislature is expected to consider retail wheeling legislation when it reconvenes in January 1998.

- A stakeholder task force has drafted a consensus bill that targets July 1, 2001 as the start date for retail competition. The bill would leave stranded cost recovery up to the Kansas Corporation Commission, permit securitization, and mandate recovery of 100 percent of regulatory assets. Cooperatives would be allowed to opt out of retail competition if members vote to do so before the start date of competition, while municipal utilities are assumed to be exempt, but can opt in at any time.

Kentucky

- While the legislature is expected to consider various electric restructuring bills, beginning in January 1998; legislative approval is not currently expected.

- The legislature has established a 20-member Interim Special Subcommittee on Energy, which held informational workshops during fall 1997.

- The Kentucky Public Service Commission is expected to complete its informal meetings with stakeholders and plans to develop draft restructuring principles in the near future.

Louisiana

- A legislative study committee met in September 1997 but put off further meetings pending recommendations from the Louisiana Public Service Commission (LPSC).

- The LPSC has indefinitely postponed its decision on whether deregulation is in the best interest of the state. A decision had been expected in November, 1997.

Maryland

- A Maryland legislative restructuring task force and the state Public Service Commission will each produce recommendations in December.

- A 20-member legislative task force, assisted by an 18-member stakeholder advisory board, is expected to make recommendations to the legislature by December 15, 1997.

- In May 1997, a PSC staff report recommended the introduction of prototype access programs and customer choice.

Michigan

- While Michigan utilities had supported a Michigan Public Service Commission (MPSC) "blueprint" for retail competition, they assert that the MPSC lacks the legal authority to force them to adopt an electric restructuring plan that they do not support.

- The utilities object to the MPSC's October 29, 1997 restructuring order, which sets forth the Commission's new method of calculating stranded costs.

- Legislative action on electric restructuring has reportedly been delayed until at least mid-1998.

Minnesota

- A 20-member legislative task force met throughout the summer to discuss electric restructuring issues (including the tax implications of electric restructuring) and may have a bill ready for legislative review by early 1998.

- A number of electric restructuring bills will carry over to the next legislative session but are reportedly not expected to pass.

- The Minnesota Public Utilities Commission is expected to issue a report in fall 1998 on the challenges associated with retail competition. This report is not expected to provide substantive recommendations.

Mississippi

- On November 1, 1997, the Mississippi Public Service Commission staff submitted a draft timetable and implementation plan for retail competition to the Commission.

- A group of industrial customers has organized a coalition which is working toward legislation for the 1998 legislative session. Prospects for legislative action are reportedly uncertain.

Missouri

- A 14-member interim task force, which was established by the legislature to examine the tax impacts of electric restructuring, met during mid- to late-1997. A report is due by year-end 1997.

- Missouri regulators are examining electric restructuring. The Missouri Public Service Commission's Retail Electric Competition Task Force is expected to issue a draft report in November 1997.

Montana

- Montana's electric restructuring law was signed by the governor on May 2, 1997. Retail choice for larger customers, and pilots for smaller customers, are to begin on July 1, 1998.

Nebraska

- None.

Nevada

- In July 1997, the Nevada legislature passed a bill that requires retail competition by December 31, 1999. The restructuring law authorizes the PUC to order divestiture, provides for licensing of alternative sellers, full shareholder compensation for those stranded costs that the PUC deems recoverable. Many details of the implementation of competition are to be determined by the PUC.

New Jersey

- Legislative action is possible, especially with respect to issues such as securitization, which exceeds the BPU's current legislative authority.

- On April 30, 1997, the New Jersey Board of Public Utilities (BPU) issued its final Energy Master Plan, which accelerates the transition to retail electric competition by 9 months from dates originally proposed in the draft plan. The BPU proposes retail competition to 10% of consumers in October 1998, with the phase-in period to a competitive marketplace to be completed by July 2000. The BPU will continue to conduct workshops and formal hearings to address the final plans' details.

New Mexico

- A legislative study committee continues to meet on electric restructuring and other issues. The legislature is expected to consider electric restructuring bills in 1998 but passage is reportedly not likely.

- A New Mexico PUC collaborative process collapsed because stakeholders were far apart.

New York

- The New York legislature failed to enact a comprehensive electric restructuring ill in 1997.

- The New York Public Service Commission (NYPSC) is implementing retail competition on a company-by-company basis through a combination of negotiated processes and adjudicatory proceedings. In addition, the PSC has begun a number of rulemakings on issues such as metering/billing and divestiture of generation.

- The NYPSC approved ConEdison's restructuring settlement with conditions.

- NYPSC Administrative Law Judges have recommended that the NYPSC reject Orange & Rockland's and Central Hudson Gas & Electric's settlements but recommended that the PSC approve Rochester Gas & Electric's settlement. A tentative agreement on Niagara Mohawk Power Corporation's revised restructuring settlement has been reached. In October 1997, New York State Electric Gas & Electric submitted a reform proposal that was more aggressive on the issues of divestiture and the start date of retail access.

North Carolina

- A 23-member study commission is to report back to the legislature in 1998 on its progress on electric restructuring and must submit recommendations on how to proceed by 1999.

- An electric restructuring bill will carry over to the 1998 session but approval is not currently expected.

- The North Carolina Utilities Commission is studying general industry trends related to industry restructuring and the actual experience since FERC issued orders on nondiscriminatory, open-access transmission.

North Dakota

- A 6-member legislative study committee is studying electric restructuring with the aim of drafting legislation for the 1999 session.

- In fall 1996, the North Dakota Public Service Commission ended its investigation of electric restructuring by concluding that it was not convinced that the electric industry is in need of an immediate and substantial overhaul.

Ohio

- A special joint legislative committee is expected to issue restructuring recommendations and a retail competition bill in December 1997. The committee's held meetings in mid-1997 with stakeholders seeking to identify areas of consensus.

- The Ohio PUC continues to hold discussions with stakeholders on generic electric restructuring issues.

Oklahoma

- On April 25, 1997, Oklahoma's governor signed into law a comprehensive electric restructuring bill, which establishes retail competition beginning in 2002.

- A legislative task force will oversee the implementation of the state's electric restructuring law. The Oklahoma Corporation Commission (OCC) is to advise the legislative task force. The OCC has discretion to determine many of the details of electric restructuring.

Oregon

- The Oregon legislature rejected electric restructuring legislation during the 1997 legislative session but established a committee to study retail competition and to attempt to draft language that is acceptable to all stakeholders.

Pennsylvania

- The legislature enacted the Electricity Generation Customer Choice and Competition Act. This comprehensive restructuring legislation was signed by the Governor on December 3, 1996. Beginning January 2001, electric generation will no longer be a regulated function. One-third of peak load demand will be provided on a retail competition basis by January 1999, two-thirds by January 2000 and full retail competition will be present by January 2001. The Commission will have some discretion to vary this schedule if necessary to preserve reliability or because of other specified considerations.

- In December 1997, the Pennsylvania Public Utility Commission (PPUC) rejected PECO Energy's restructuring settlement, and a proposal by Enron, in a 3-2 vote. Instead, the Commission established a restructuring plan that: (1) accelerates the introduction of retail competition by one year; (2) cuts its stranded costs by about $500 million; and (3) provides larger generation credits for outside suppliers to compete against (4.46 cents/kWh versus PECO's 2.3 cents/kWh). The PPUC rejected the PECO restructuring settlement because it hindered a competitive retail market, delayed competition to residential customers until 2003, and provided insufficient decreases in retail rates. The PPUC rejected Enron's plan because it required PECO's willingness to be the "service company," under Enron's terms and conditions, which PECO was unwilling to agree to.

South Carolina

- An electric restructuring bill carried over to the 1998 legislative session. An 8-member House public utilities subcommittee is exploring electric restructuring issues.

- The Speaker of the House asked the Public Service Commission to submit an electric restructuring proposal by January 31, 1998.

South Dakota

- None. PUC is monitoring other states' activities.

Tennessee

- The Legislature's Special Joint Committee to Study Electric Utility Restructuring held its first meeting in September 1997. The Tennessee Valley Authority, which serves most customers in the state, is exempt from state regulation. The study committee is to report its findings by February 28, 1998.

Texas

- The legislature failed to pass electric restructuring legislation during the 1997 session.

- Texas' lieutenant governor established a 7-member legislative committee to explore electric restructuring issues, which is expected to develop recommendations for the next regular legislative session in 1999. The committee is expected to issue a status report by March 1, 1998 and a final report by October 1, 1998.

- The Texas Public Utilities Commission has opened an investigation into the competitiveness of the wholesale market and continues inquiries into unbundling of distribution functions and power pool interconnection issues

Utah

- A joint legislative task force was established by law in March 1997 to study restructuring issues. Reports are due in November 1997 and November 1998.

- The Utah PSC has completed its informal restructuring inquiry. The PSC provided background information, but not recommendations, to the joint legislative task force.

Virginia

- The legislature established a seven-member joint subcommittee to study electric restructuring issues. The joint subcommittee is coordinating its study with the State Corporation Commission's (SCC's) investigation. A report is due during the 1998 legislative session. Legislation that provides the framework for a move to retail competition is possible but comprehensive legislation is not expected.

- On November 7, 1997, the SCC's staff filed a report that recommended a "deliberate and cautious" movement to retail competition by 2002. Initial steps would be to form an independent system operator and a regional power exchange.

Washington

- The Washington state legislature failed to pass comprehensive electric restructuring bill and instead established a task force to study the issue.

West Virginia

- The Public Service Commission's restructuring held meetings in mid-1997 and released a draft report on October 15, 1997. A final report is expected in December 1997.

Wisconsin

- In October 1997, the Public Service Commission deemphasized retail competition and instead will emphasize improvements to the state's electricity infrastructure and reliability. Outages at the state's nuclear plants in mid-1997 had focused attention on reliability and transmission bottlenecks.

- Wisconsin's governor has received reports from four stakeholder groups on reliability issues. Legislation on reliability issues and merchant independent power plants is reportedly likely during 1998.

Wyoming

- A consultant hired by the Wyoming PSC found that because Wyoming's prices average 30 percent below national levels, short-term power price reductions would only occur if utilities were precluded from recovering stranded costs. The PSC reportedly will recommend that the legislature use this report as a basis for addressing electric restructuring.

Electric Restructuring Implementation

11-Dec-97

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Billing/metering competition (major sub rule)														>							<-										Carol(L),Denis,Norm,Grant,Betty
S. 3203																															
Info disclosure (major sub rule)								>												<-											Lisa(L),Phil,Matt,Mitch,Joe,Betty
Licensing (tech rule)																															
Consumer protection (tech rule)																															
S. 3204																															
Divesture plans & asset sales (adjudication)																									<-						Kivela(L),Faith,Peter,Sharon,Jim,Angela,Consul
Divesture date extension (major sub rule)								>						<-																	Same
Sale of capacity/energy (major sub rule)									>								<-														Same
S. 3205																															
Marketing, large IOUs (major sub rule)								>													<-										Angela(L),Grant,Lisa,Joanne
Study re: market share limitation																															
S. 3206																															
Marketing, small IOUs (major sub rule)								>													<-										Angela(L),Grant,Lisa,Joanne
Study re: access for non-NEPOOL utilites																			<-												Denis,Norm,Bill,Consultant
S. 3207																															
Marketing, COUs (tech rule)								>													<-										Angela(L),Grant,Lisa,Joanne
S. 3208, 3209																															
Stranded cost/T&D rev. req./rate design (adjud																															
CMP																		<-													Faith(L),Kania(L),Mitch,Angela,Grant,
MPS																			<-												Jim,Bill,Sharon,Chuck,Kivela,Wayne,Consultan
BHE																								<-							
COUs - all																									<-						
Notes: Statutory deadline for stranded cost & rev. req 7-1-99; rate design 10-1-99.																															
Completion dates shown above may reflect initial decisions and allow for subsequent compliance or update phases																															
S. 3210																															
Portfolio req. impl. (major sub rule)								>									<-														Sharon(L),Denis,Joanne
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... gy efficiency progs (major sub rule)					>										<-																Denis(L),Sharon,Eric,Joanne
S. 3212																															
Standard offer T&C (major sub rule)		>						<-																							Peter(L),Jim,Matt,Bill,Norm,Betty,Consultant
Standard offer bidding rules (major sub rule)		>						<-																							Consultant, above staff
Standard offer bidding/selection																									<-						Consultant, above staff
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S. 3214																															
Low-income prog/funding levels												>										<-									Derek/Betty(L),Eric,Lisa
S. 3215																															
Federal proceedings																															Denis,Mitch,Jim,Sharon
S. 3216																															
Utility employees, transition (tech rule)				>							<-																				Wayne(L),Grant,Trina
S. 3217																															
Annual report																															Gil,Steering com,Wayne
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QF contract issues (tech rule)/ Ch. 36 rulemaki		>							<-																						Bill(L),Faith,Angela,Mitch
Low-income study/proposed legislation							<-																								Gil(L),Derek/Betty,Eric
Conforming amendments																		<-													Gill,Mitch,Jim
Other																															
Impacts of 30% portfolio req.					<-																										Consultant
Load profiling						>									<-																Denis,Angela
Market power study (draft by 2-1;final by 12-1-																		<-													Ackerman,Denis,Sharon,Mitch

NOI Phase

Rulemaking Phase/Adjudication/Other

<- Deadline

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-794

March 10, 1998

PUBLIC UTILITIES COMMISSION
Rulemaking on Qualifying Facility
Rates, Terms, and Conditions in
Restructured Electric Industry
(Chapter 360)

ORDER ADOPTING AMENDED
RULE AND STATEMENT OF
FACTUAL AND POLICY BASIS

WELCH, Chairman; NUGENT and HUNT, Commissioners

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I. INTRODUCTION

In this Order, we adopt amendments to Chapter 36[1] of our rules, Cogeneration and Small Power Production, in accordance with recent legislation that restructures the electric industry in Maine.[2]

During its 1997 session, the Legislature fundamentally altered the electric utility industry in Maine by deregulating electric generation services and allowing for retail competition beginning on March 1, 2000. At that time, Maine's electricity consumers will be able to choose a generation provider from a competitive market. As part of the restructuring process, the Act requires utilities to divest their generation assets and prohibits their participation in the generation services markets.[3] These changes in industry structure create numerous implications for existing contractual relationships between qualifying facilities (QFs) and utilities.

Maine utilities signed power purchase contracts with QFs as a result of federal and state policies adopted to promote the private development of renewable resources and efficient energy production. The federal Public Utilities Regulatory Policy Act (PURPA) and Maine's Small Power Production Act (SPPA) required utilities to enter long-term purchase power contracts with QFs.[4] Many of the contracts Maine's utilities have entered into with QFs extend beyond the March 1, 2000 implementation of retail competition. The parties entered these contracts at a time when electric utilities provided vertically integrated retail service on a monopoly basis. This industry structure had existed for many decades; as a consequence, the contracts reasonably

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[1]The Commission's current practice is to use three-digit designations for rules; accordingly, Chapter 36 will become Chapter 360.

[2]An Act to Restructure the State's Electric Industry (the Act), P.L. 1997, ch. 316.

[3]Utility affiliates may participate in the generation market. 35-A M.R.S.A. §§ 3205, 3206, 3207.

[4]Qualifying facilities are generally renewable power producers under 80 MW or cogenerators that meet specified efficiency standards. <u>See</u> 35-A M.R.S.A. § 3303.

contemplated that this structure would continue to exist into the future. Thus, efforts to restructure the industry should treat both QFs and utilities fairly, and not unreasonably frustrate the expectations of contracting parties.

II. STATUTORY PROVISIONS

The Act contains several provisions regarding QFs in a restructured industry. Section 5 specifies that QF contracts shall continue in effect after restructuring and that the rights of contracting parties may not be impaired as a result of implementing the Act. Section 6 establishes a method to determine the rates for power purchases in contracts that tie such rates to the utility's retail rates. Under section 7, the Commission must continue to establish short-term-energy-only (STEO) rates to fulfill the terms of existing QF contracts. Section 8 requires the Commission, by rule, to establish a method to set long-term avoided costs and any rate, term, condition or other provision of a QF contract that may be rendered impractical or impossible to perform or implement as a result of industry restructuring. Finally, section 9 states that no utility may be required, pursuant to Title 35-A, Chapter 33, to enter into a contract to purchase power from a QF; the section does not abrogate any existing law or rules that provide QFs with the right to sell energy prior to March 1, 2000 on an "as available" basis.

Chapter 36 of the Commission's rules governs utility power purchases from QFs. We amend Chapter 36 to conform with the Act and establish rules for QF purchases in a restructured industry. Generally, the amended rule eliminates or revises provisions that are premised on requirements that utilities enter long-term contracts with QFs, revises provisions to determine STEO rates and rates for purchases of energy and capacity in a competitive market, provides for existing net energy billing arrangements, and adopts a process for establishing substitute contractual rates, terms or conditions that are rendered impractical or impossible to perform as a result of restructuring. We discuss the specific revisions and amendments to Chapter 36 in section IV below.

III. RULEMAKING PROCESS

On October 31, 1997, we issued a Notice of Rulemaking and proposed rule amending Chapter 36. Prior to initiating the formal rulemaking process, we conducted an inquiry into the effects of industry restructuring on QF contracts (Docket No. 97-497); we received numerous comments from interested persons on how we should amend Chapter 36 in light of industry restructuring. The comments obtained in the Inquiry were constructive in the development of the proposed rule.

Consistent with rulemaking procedures, interested persons were provided an opportunity to provide written and oral comments on the proposed changes to the rule. The following persons filed comments: the Public Advocate; Cental Maine Power Company (CMP);[5] S.D. Warren Company, Maine Energy Recovery Company, the Independent Energy Producers of Maine, Wheelabrator-Sherman Energy Company and Benton Falls Associates (Consolidated QFs); Regional Waste Systems (RWS); Maine Renewable Energy (MRE); Renewable Energy Assistance Project (READ); Peter Talmage and Naoto Inoue; and William Lord. The Commission appreciates the efforts of all interested persons in providing comments on the issues presented by this rulemaking. The comments were extremely helpful in our consideration of how Chapter 36 should be amended as a consequence of industry restructuring and to comply with legislative directives contained in the Act.

IV. DISCUSSION OF INDIVIDUAL SECTIONS AND COMMENTS

In this section of the Order, we discuss the individual sections of the amended rule, positions of commenters, and our rationale for either maintaining or modifying the provisions of the proposed rule.

A. Section 1: General Provisions

The proposed rule amended the definitions section to delete, add, or modify existing definitions to be consistent with the changes proposed throughout the rule. CMP, RWS and the Consolidated QFs commented on this section.

RWS expressed concern with adding a reference to transmission and distribution utilities to the definition of avoided costs as potentially creating ambiguity in contracts. We disagree. In amending Chapter 36 in light of restructuring, we must recognize that electric utilities will become transmission

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[5]Bangor Hydro-Electric Company filed a letter indicating general agreement with CMP's comments.

and distribution (T&D) utilities. Additionally, RWS did not explain how such a change may create ambiguity in contracts.

CMP stated that the definition of "avoided costs" is problematic because it assumes that T&D utilities will continue to have an obligation to obtain resources to provide retail generation service after retail competition begins. CMP suggested that the definition state that, after February 28, 2000, avoided costs should equal a market rate. RWS opposed such a change, stating that avoided costs were never intended to be a market rate. We agree with CMP's comments and have amended the definition to state that, after the initiation of retail competition, avoided costs shall mean the market value of the power supplied by the QFs.[6]

CMP also commented that the definition of "long-term contract" is unnecessary because the term is not contained in the proposed rule. We agree and have deleted the definition.

CMP noted that the definition of "net energy billing" implies the use of a single meter when this is not required by the rule. We decline to change the definition that has been in place since the original adoption of Chapter 36. The net billing provision continues to specify that a utility may install a second meter as long as the QF is not charged for its associated costs.

The Consolidated QFs commented that the proposed rule deleted the definitions of "affiliate" and "associate" and both may still be necessary because of the continued provision (section 4(A)(3)) that QFs may generate or distribute electricity through its or its associates' private property for its or its associates' use, without approval or regulation by the Commission. The proposed rule removed the definition of "affiliate" and "associate" because it deleted the affiliate wheeling provision that contained those terms. Because the amended rule contains the term associate and the definition of

[6]We note that the concept of avoided costs in Maine has evolved to effectively mean the market value of power; this occurred through policies requiring competitive bidding and by recognizing that existing utility resources may be avoided at a market price. Additionally, section 7 of the Act defines STEO rates as a wholesale market price.

that term refers to affiliate, we have reinstated both definitions.

The Consolidated QFs also suggested that the added definition of "existing contracts" be modified to include amendments to existing contracts. We agree and have added such language to the definition.

We have deleted the definition of "production run" because that term is not used in the amended rule.

Finally, CMP commented that, with respect to provision in section 1 that allows for exceptions to the rule to "further the purposes and policies of this Chapter," the Commission should include a basis statement that references the relevant sections of the Act. Such a basis statement is included. We have also added language clarifying that the Commission on its own motion may consider deviations from the rule's provisions.

Except for the changes described above, the amended rule maintains the modifications contained in this section of the proposed rule.

B. <u>Section 2: Qualifying Cogeneration and Small Power Production Facilities</u>

This section contains the requirements for a generating facility to be considered a QF. Because QF contracts will remain effective after retail competition, the proposed rule did not amend this section. However, in our Notice of Rulemaking, we commented that there may be a need to amend subsection D (Ownership Criteria) which states that a QF may not be owned by an entity primarily engaged in the generation or sale of electricity. We noted that it appears that this section was intended to prevent electric utilities from obtaining QF status and that, after industry restructuring, the current rule would prevent competitive electricity providers from owning QFs. Because of the possibility that this provision may create unintended results in a restructured industry, we asked for comments on whether and how it should be amended.

The Consolidated QFs provided the only response to this matter, proposing that effective on the date of retail competition the existing language should be replaced with a prohibition on QF ownership by a T&D utility or affiliate. The amended rule contains this modification.

CMP proposed that this section of the rule include monitoring requirements to ensure that facilities are maintaining the standards necessary for QF status. The Consolidated QFs, Benton Falls and MRE opposed such requirements, arguing that monitoring provisions should be a matter of the individual contracts, rather than administrative requirements, that the proposal is outside the scope of the rulemaking, and that it is an unfair leverage tactic.

We have not considered CMP's proposed monitoring program because it is beyond the scope of this rulemaking proceeding, which relates to the impact of restructuring on QF contractual relationships. In an appropriate proceeding, we would consider adopting monitoring requirements that are not unreasonably burdensome if CMP demonstrates that a reasonable possibility of non-compliance exists to justify such data collection and verification requirements.[7]

C. Section 3: Administrative Determination of Avoided Costs

1. Proposed Rule and Comments

In this section of the proposed rule,[8] we removed filing requirements premised on an integrated retail monopoly industry structure and replaced them with requirements that are consistent with the emerging competitive markets for electricity. The deleted items included long-term load forecasts, long-term energy resource plans, the projected cost of planned capacity additions, and long-term avoided costs calculated as the difference between total production costs of various energy resource plans. The proposed rule also eliminated, as no longer necessary, the requirement that utilities notify the Commission if avoided costs have changed by 10% or more.

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[7]For example, we would expect CMP to provide us information on QF non-compliance found in other jurisdictions and evidence it has that Maine QFs may not be in compliance.

[8]This section of the rule was originally titled "Availability of Electric Utility System Cost Data."

The proposed rule included new provisions requiring estimated market prices for wholesale energy in Maine, estimated market value of wholesale capacity in Maine, projections of capacity excesses and deficiencies, and the estimated cost of installing new peaking capacity in New England. In our Notice of Rulemaking, we stated that this market-based capacity and energy cost data would allow the Commission to continue to set energy and capacity rates through an administrative process, and if we adopt a formula approach to establishing avoided capacity and energy costs, the provisions of section 3 would cease to apply as unnecessary beginning on the date of retail access.

CMP commented that, after retail access, T&D utilities should not have to supply generation cost data because they will no longer be in the generation business and it would require maintaining expertise in the area. CMP noted that use of market rates would be more accurate and less subjective than estimating avoided costs. CMP also questioned requiring such data prior to retail access because until then the Commission will continue calculating avoided costs using historic methods of calculating avoided costs.

The Consolidated QFs stated that this section of the rule should contain more specifics as to how avoided costs will be determined, including a more precise definition of wholesale energy and a requirement that costs be set for a one year period. The Consolidated QFs also suggested that the rule specify the term of capacity purchases and the estimated cost of peaking capacity in Maine rather than New England.

2. <u>Discussion</u>

The amended rule maintains the deletions contained in the proposed rule, and includes methodologies for determining avoided costs (rather then the detailed list of cost data included in the proposed rule). These changes update this section of Chapter 36 to include information we now use when determining avoided costs and to eliminate provisions that have become outdated. The deleted provisions are premised on the existence of long-term generation planning by utilities, which no longer occurs because: (1) utilities have had surplus generation; (2) utilities have been meeting generation needs through shorter term purchases; and (3) utilities will only be acquiring and supplying generation for about two more years. We agree with the

Consolidated QFs, however, that the rule should be more specific as to how we will calculate avoided costs administratively. We have added provisions that specify how administratively-set avoided costs will be calculated. These calculations will be much as they are now, but will also reflect recent and future changes in how utilities provide energy and capacity.

The information filing requirements and the administrative methodologies for calculating avoided costs will remain only until the beginning of retail access. We concur with CMP that an objective measure of market rates is a better way to set avoided costs after retail access than administratively-determined estimates of future wholesale prices. As discussed below, we have adopted an approach for establishing both long-term and short-term avoided costs that relies on actual market prices for QF power that should avoid the need for administrative estimates after retail access. Accordingly, the amended rule specifies that the provisions of section 3 will not be effective beginning with the date of retail access.

D. <u>Section 4: Arrangements Between Utilities and Qualifying Facilities</u>

1. <u>Proposed Rule</u>

Consistent with section 9 of the Act, the proposed rule eliminated all provisions of the Chapter premised on a continued requirement that utilities enter new purchased power contracts pursuant to Title 35-A, Chapter 33, and maintained the requirement and related provisions to purchase energy on an as-available basis at STEO rates. The proposed rule also eliminated outdated methods of calculating avoided cost and the fourth decrement avoided costs listed in section 4(C)(3).

As mentioned above, sections 7 and 8 of the Act require the Commission to periodically set STEO rates and to adopt a method for establishing terms related to long-term avoided costs. The proposed rule implemented these requirements in separate subsections governing the rates for short-term energy purchases and for capacity and energy purchases. Both subsections specified that, prior to the date of retail access, the Commission would continue to establish rates for purchases through an administrative process based on the information filed in accordance with section 3 of the rule. Both subsections also contained two alternatives to establish rates after the date of retail access: (1) a formula approach that would determine rates monthly based on ISO-NE clearing prices; or (2) an administrative process that would determine rates annually based on projections of wholesale electricity prices.

The proposed rule also maintained the existing provisions on factors affecting purchase rates. Such factors include dispatchability, coordinated scheduled outages, and reduced line losses. In light of the proposed rule's reliance on actual market information to establish rates, we requested comment on whether these provisions remain appropriate.

CMP and the Consolidated QFs provided numerous comments on the "utility obligations" and "rates for purchases" subsections.

2. Utility Obligations

CMP commented that, consistent with section 9 of the Act, this provision should specify that the utilities' obligation to purchase energy on an as available basis at STEO rates would not exist after the beginning of retail access. We agree and have included language in the amended rule stating that the obligation ceases on February 28, 2000.

CMP also expressed concern that the provision requiring utilities to sell T&D services to QFs not convey any special rights or entitlements. The Consolidated QFs stated this provision should specify that utilities shall not discriminate against QFs in providing T&D services. The language in the proposed rule mirrors that in the existing rule and clearly conveys that utilities shall provide service to QFs in the same manner as any other customer -- without undue discrimination or special entitlement. We see no reason to modify the language of the proposed rule.

Finally, CMP suggested that a requirement should be added that QFs meet the utility's technical interconnection requirements prior to being interconnected. This is not a matter affected by industry restructuring, and we are not aware of any problems in this regard under the existing rule; accordingly, we decline CMP's suggestion.

3. Rates for Purchases

a. Prior to Retail Access

Both CMP and the Consolidated QFs stated that it would be useful for the Commission to specify the methodology it will use to establish avoided cost rates prior to retail access. As discussed in section IV(C) of this Order, we agree that the amended rule should contain a description of the methodologies we will use to establish STEO and energy and capacity avoided costs prior to retail access. Such provisions are contained in section 3 of the amended rule.

b. After Retail Access

i) Comments

With respect to the two alternatives presented in the proposed rule, CMP preferred the formula to that of an administrative approach, but believes there is a better alternative. CMP suggested that the price obtained from its sale of the rights to the power from QF contracts be used to establish both STEO rates and avoided energy and capacity costs. CMP stated this approach would avoid the possibility of creating additional stranded costs. CMP opposed the administrative process alternative because it would require T&D utilities to propose rates that reflect future wholesale generation costs that, after February 2000, will become an area irrelevant to their core business.

CMP stated that dispatchability, maintenance scheduling, and line loss adders would be reflected in either the price received for QF contract output or the ISO-NE clearing price. Additionally, by definition STEO is intermittent, as-available energy that is not pre-scheduled (for dispatchability or maintenance) so that references to adjustments for dispatchability and scheduled maintenance should be deleted from the STEO section. Finally, CMP stated that, because T&D utilities will not be selling generation, there will in effect be no associated line loss saving from having generation sources closer to retail customers; because there is no line loss benefit being provided, no corresponding adjustment should be made to rates paid to QFs.

The Consolidated QFs argued that the formula approach to establishing STEO rates in the proposed rule is not appropriate because it is a New England price that might not reflect Maine-specific factors; the approach does not satisfy the specific requirements of section 7 of the Act and is thus not permitted by the law. The Consolidated QFs supported a revised version of the second alternative that explicitly incorporates the section 7 criteria and provides a clear mechanism for developing Maine-based STEO rates.[9]

For similar reasons, the Consolidated QFs opposed the formula approach and supported a revised version of the administrative process alternative for capacity and energy. They argued that use of a current market price for capacity would not comply with section 8 of the Act because it would not be equivalent to long-term avoided costs as historically determined by the Commission and that it would not capture the value of longer term commitments. The Consolidated QFs urged the Commission to develop a methodology for establishing true long-term avoided costs.[10] Finally, the Consolidated QFs, Benton Falls and MRE disagreed with CMP that the rule's factors affecting rates (e.g., dispatchability, scheduled maintenance, line loss reduction) are either captured in a market rate or inapplicable in a restructured industry.

ii) Discussion

The amended rule does not include either of the proposed rule's alternatives for STEO or capacity and energy avoided costs. Instead, the amended rule adopts the basic approach initially proposed by CMP that uses the sale of the output of QF contracts, pursuant to 35-A M.R.S.A. § 3204(4), as the basis for establishing avoided costs. The approach has several important advantages: it will accurately reflect the market value of the power at the time of the sale; it will be easy to administer; it is consistent with the Act's directives; and it will eliminate the potential to create new stranded costs,

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[9]The Consolidated QFs did not propose any such mechanism nor did it explain the concept of Maine-based STEO rates. Maine is part of an integrated New England electricity market; for the most part, there is no Maine-specific market.

[10]Again, the Consolidated QFs did not propose any specific methodology.

because it precisely matches what the utility pays QFs with what the utility receives for the power in the market.[11]

Specifically, we will require that the sale of QF contract output pursuant to 35-A M.R.S.A. § 3204(4) contain separately stated capacity and energy prices for on-peak and off-peak periods for each month of the duration of the sale.[12] Utilities that have QF contracts with STEO or avoided capacity and energy provisions will make periodic filings containing monthly, time-differentiated energy and capacity rates that will equal the section 3204(4) sale prices. The STEO avoided costs will be the energy-only rates and the capacity and energy avoided costs will be the capacity and energy rates. The STEO filing will be made annually and contain rates for the following 12 months.[13] The capacity and energy rates filing will contain rates for the entire sale duration; new filings are required after each new section 3204(4) QF output sale.[14]

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[11]Although CMP proposed this approach in the Inquiry that preceded this rulemaking, we did not include it in the proposed rule because, at the time, CMP included its QF contracts as part of its divestiture bid package. Because of the bid design, it would have been impossible to implement CMP's proposal without administrative processes to transform the QF sale results into time-differentiated, unbundled energy and capacity rates as required by the Act. Thus, although divestiture would have provided information the Commission would use in setting avoided costs, it would not have obviated the need for administrative proceedings to set avoided costs. Now that CMP has determined it will not sell the QF output as part of its divestiture but pursuant to Commission rules proscribing the terms of the sale, this approach becomes workable.

[12]We will determine the sale duration in the section 3204(4) rulemaking so as to maximize bid prices and hedge against risk.

[13]If the sale duration is more than 1 year (e.g., 3 years), the utility's initial STEO filing will contain the first year's sale prices; in the second year, the utility's STEO filing will contain the second year's sale prices; the third year filing will contain the third year's sale prices.

[14]If our section 3204(4) rulemaking reveals that our decisions here are either unworkable or might tend to reduce the

Utilities will file the avoided costs on January 15, beginning in 2000, and provide copies to interested persons on a predetermined service list. Interested persons may object to the avoided cost filing by February 15. The objections must include a showing that the filed rates do not reasonably represent wholesale prices in Maine or are otherwise contrary to law. If no objections are received, the rates will become effective unless suspended by the Commission or its Director of Technical Analysis. If objections are received, the Commission or its Director of Technical Analysis may suspend the rates from becoming effective. If not suspended, the rates will become effective on March 1. In the event the rates are suspended, the Commission will adopt a procedure to determine the avoided cost rates.

This approach complies with the section 7 requirements regarding STEO rates. Under the amended rule, the Commission will establish STEO rates "no less frequently than annually . . . for the 12-month period succeeding the annual date of establishment . . . " The rates will be time-differentiated, using current peak and off-peak periods and represent an accurate estimate of wholesale energy costs in Maine that include fuel, start-up, and variable operating and maintenance costs. Section 7 states that STEO rates should be "adjusted to reflect line loss costs or savings." To the extent there are line loss effects, they should be captured in the market prices. Accordingly, we have not included a line loss adjustment. Under the amended rule, however, QFs may argue for a line loss adjustment by objecting to the utility's filed rates. We have also declined to include specific adjustments for scheduled maintenance and dispatchability as generally not applicable because STEO rates are for as-available energy. As stated above, the amended rule allows the Commission to establish different rates upon a showing that the bid prices are not representative of wholesale costs in Maine. In such a situation, the Commission, consistent with the provisions of section 7 of the Act, would consider historic market prices, as well as generally available indicators of market prices. Interested persons would also have an opportunity to make a showing that the Commission should allow an adjustment

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value utilities might receive for QF power, we will immediately reopen this Chapter and adopt alternative avoided cost methodologies.

for scheduled maintenance or dispatchability, as well as line losses.

With respect to energy and capacity costs, the amended rule is consistent with section 8 of the Act that requires the Commission to adopt a method for establishing terms related to long-term avoided costs that preserve the intent and purposes embodied in the contractual provisions. As we stated above, avoided cost calculations in Maine measure market value of power and, as such, reliance on direct market indicator to establish avoided costs cannot be considered as violative of the intent and purposes of QF contracts. Additionally, any approach that relies on longer term projections of future cost (either administratively determined or by formula) risks creation of stranded costs because the avoided costs paid to the QF would not match what CMP obtains for the very same power on the market. Our view is that the Legislature did not intend to preclude a methodology that establishes future avoided costs in a manner that minimizes the possibility of creating new stranded costs by relying on an easily determined value of QF power in the market.

Although section 8 requires the Commission to maintain the intent and purposes of contracts, the contracting parties do not have a reasonable expectation for any particular methodology for establishing avoided costs or that an existing methodology would remain unchanged indefinitely. Even without industry restructuring, the Commission could have amended the methodology in Chapter 36 to a market-based or formula approach. In fact, this is what the Commission did in effect when it moved to a competitive bidding system for all QFs greater than a 1 MW. The language in section 8 of the Act cannot reasonably be read to require the Commission to set future avoided costs using outdated processes that ignore the reality that the industry has changed. In response to the Consolidated QFs' argument that our methodology must reflect the value of long-term commitments to provide power, we agree with CMP comments during the rulemaking hearing. As a general principle, the value of power over the long term should equate to the sum of shorter term prices; thus our approach does not violate any expectations in this regard.[15]

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[15]The Consolidated QFs' view appears to be based on the capacity and regulatory situation in the 1980s when there was a generally accepted value to a commitment to provide power over relatively long periods. It was this generally held perception that has resulted, to some degree, in the current stranded cost

Finally, the amended rule maintains the list of "factors affecting rates for purchases" (e.g., dispatchability, scheduled maintenance), modified to be consistent with other changes to the amended rule. Our view is that the rule's market approach will capture the benefits of the listed items (if those benefits continue to exist). The consideration of the listed factors is permissive under the amended rule, allowing us to adjust to purchase rates if, in the context of a suspended avoided cost filing, it is demonstrated that an adjustment is warranted.

Except for the changes described above, the amended rule maintains the modifications contained in this section of the proposed rule.

E. <u>Section 5: Net Energy Billing</u>

1. <u>Proposed Rule</u>

When initially adopted, Chapter 36 contained a provision allowing QFs with an installed capacity of 100 kW or less the option to buy and sell electricity on a net energy basis. The purpose of this provision was to facilitate the development of very small QFs by allowing them to sell their excess generation to utilities without incurring the costs associated with a second meter. The proposed rule maintained the existing net energy billing provision until March 1, 2000 and included two alternatives for similar arrangements after that date.[16]

For QFs with existing net energy billing agreements that extend past March 1, 2000, the proposed rule specified that T&D utilities would continue to bill on a net energy basis; the proposed rule also contemplated that the T&D utility would purchase any excess generation and include it with generation from all other existing QF contracts for sale under the terms of 35-A M.R.S.A. § 3204(4). We sought comment,

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problem. In the future unregulated market, generation providers may instead offer <u>discounts</u> to customers (either wholesale or retail) that commit to buy power over long periods of time.

[16]These provisions were moved to a separate section in the rule.

however, on whether it would be more desirable for the rule to allow competitive providers or to direct or allow standard offer providers to purchase the excess generation.

For net billing arrangements after March 1, 2000, the proposed rule contained two alternatives. The first alternative would maintain the definition of net energy billing as it currently exists and allow a net billing customer to choose any competitive provider that is willing to offer service and purchase energy on a net basis pursuant to agreed upon rates. If the customer takes generation service from the standard offer, the proposed rule required the standard offer provider to purchase excess energy on a net basis at STEO rates established under this rule.

The second alternative would change the approach to net energy billing by requiring the installation of two meters, one measuring the energy the customer draws from the system and the other measuring the energy the customer provides to the system. At the end of the billing cycle, the customer would be billed for the usage shown on the first meter and paid for the energy provided as shown on the second meter. The proposed rule defined this approach as instantaneous net energy billing.[17] The customer's options to purchase from the competitive market and sell excess generation to its competitive provider, or purchase and sell to the standard offer provider(s) were the same as the first alternative. We sought comment on whether the use of two meters for customers with small generating facilities is necessary or desirable and, if so, whether the billing and metering approach contained in the second alternative would be more accurate; we also asked if it would be more appropriate to directly charge the customer for the second meter and associated connection costs.

With respect to either of the net billing alternatives, we asked for comment on whether the 100 kW or less qualification for net energy billing should be reduced (e.g., 10

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[17] We proposed the second alternative as a result of information and arguments provided in a recently-concluded proceeding, Talmage/Inoue Petitions, Docket Nos. 97-513/97-532, in which CMP revealed that, despite the existing rule's premise of a single meter, it has routinely installed two meters because of the need to identify the amount of energy consumed for state sale tax purposes.

kW) and whether the option should be limited to residential customers. We also asked for comment on whether only generation-related costs should be billed on a net energy basis. Finally, we sought comment on whether the net energy billing rule should contain a provision for a Commission-approved standard form contract.

2. Comments

Messrs. Talmage and Inoue provided extensive comments on the net billing issues. As a general matter, Messrs. Talmage and Inoue commented that net billing provides a simple, inexpensive and easily-administered mechanism to allow Maine residents to contribute more directly to the State's goal of encouraging customers to invest in generating technologies that use renewable and indigenous resources. Messrs. Talmage and Inoue supported leaving the obligation with the T&D utilities as a default for dealing with existing contracts that extend past March 1, 2000, but giving customers the option of voluntarily transferring the arrangements to competitive electricity providers. Regarding new net billing arrangements after March 1, 2000, Messrs. Talmage and Inoue supported the first alternative of the two presented in the proposed rule as maintaining the advantages associated with the existing net billing requirements (single meter simplifying interconnection, meter reading, and accounting). They commented that the second alternative is not a true net billing approach and is rather a net purchase and sale arrangement that is inferior to the first alternative because it increases cost and complexity by requiring the use of two non-standard meters, results in inequitable pricing, and distorts incentives for energy use by customers.

Messrs. Talmage and Inoue also suggested an additional alternative that they consider the preferred approach. Under this alternative, any excess generation in a given billing period is credited or rolled over to the following month, thereby eliminating the need for the purchase of excess generation by a utility or a competitive provider; the roll-over continues until the end of the calendar year, at which time any unused credit is granted back to the competitive provider without any compensation to the customer. The approach simplifies the arrangement by eliminating what may be a costly and cumbersome process associated with having competitive providers purchase very small amounts of energy. It also discourages net billing customers from oversizing their systems to generate more electricity than they consume over the year, since they will not be compensated for any unused credit; this is consistent with the implicit goal of net energy billing of allowing customers to offset their own electricity purchases rather than to produce power for sale in a wholesale market. Messrs. Talmage and Inoue indicated that several states, including California, Maryland, Nevada, New York, and Rhode Island, either allow or require annualization of the net billing calculation.

Messrs. Talmage and Inoue also commented that if the Commission continues to allow two meters, the customer should not pay for the second meter because it would unnecessarily discourage the installation of small renewable facilities. They proposed that net billing arrangements continue to be required for customers with generating facilities that have peak generation capacity of 100 kW or less; this capacity limit would allow the use of solar, wind, and microhydro systems for residential, small commercial, and farm-scale applications, while excluding larger, utility-scale facilities that use technologies designed to generate both power for sale on the interstate grid. The 100 MW capacity limit also corresponds with the most common capacity limit in other states that offer net billing. They also stated that there is no reason to limit net billing to residential customers and suggested that the rule include renewable resource technologies as defined in section 3210 of the Act. Messrs. Talmage and Inoue commented that customers should be allowed to net generation as well as T&D costs so as not to dramatically reduce the economic benefits of net billing and thus discourage customers from investing in small-scale renewable generation. Finally, Messrs. Talmage and Inoue stated that it is important to have a Commission-approved standard form contract to avoid the need and expense of having to negotiate with utilities over terms and conditions of interconnection and operation.

Mr. Lord, MRE, REAP, and the Public Advocate also provided comments in favor of the continuation of net billing. Mr. Lord and the Public Advocate supported Messrs. Talmage and Inoue's proposal for annualized net billing, the use of a single meter, and the use of a standard contract. MRE and REAP strongly supported the continuation of net billing for small generators as essential to further the intention of the Legislature in promoting renewable and distributed generation and argued that the second alternative negates this goal by changing the character of net billing to a purchase and sale arrangement. MRE stated that the purpose of net billing is not only to avoid the cost of installing a second meter, but represents a method for small generators to purchase back-up power at non-discriminatory and reasonable rates. MRE also expressed concerns that T&D rates and stranded cost charges may, if designed to be less usage sensitive, significantly reduce the economics of the small systems. MRE commented that the cost of the second meter should not be charged to the customer, because the utilities have provided no credible argument that these costs place an undue burden on utilities. MRE and REAP supported the continuation of the 100 kW threshold in light of the lack of any evidence to suggest that this has created any problems. REAP opposed limiting the option to residential customers because businesses with small generating facilities should not be precluded from such arrangements. The Public Advocate supported requiring the standard offer provider, rather than the T&D utility, to purchase excess generation. Finally, MRE stated the qualifications in the current rule should be replaced by a simple requirement that customers use waste heat to meet a significant part of the heat requirement that would otherwise require the consumption of additional fossil fuels.

The consolidated QFs stated that the "existing contracts" provision in the net billing section of the rule be modified to specify existing contracts for net billing customers so as not to create confusion regarding other QF contracts.

CMP commented that net billing arrangements result in unnecessary costs, because it, in effect, pays for the netted generation at retail rates, and that it must install a second meter for purposes of computing sales tax liability.[18] CMP suggested that small QFs should be treated like any other QFs and commented that the second alternative differs from this treatment only in that it does not require the QF to pay for the second meter. Of the two alternatives presented, CMP prefers the second alternative. If new net billing arrangements are required, CMP stated they should be limited to residential electricity usage and should be limited to an installed capacity of 10 kW or less. CMP commented that net energy billing should focus on the offsetting of retail load and, therefore, the proper size limitation should correspond to that necessary to offset the

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[18]CMP also argued that the net billing provisions are not in accordance with either federal or state law and should be deleted in their entirety. The Commission has addressed the legality of existing provisions and found them to be lawful under both federal and state law. Talmage/Inoue, Docket Nos. 97-513/97-532 (Oct. 27, 1997).

average retail load of a residence; 100 kW is far in excess of the amount necessary to offset retail load at a typical residence, 10 kW is a much more realistic number. Finally, CMP commented that, assuming these arrangements continue, customers should pay the full T&D costs because such costs are not avoided as long as these customers remain on the system.

3. <u>Discussion</u>

a. <u>Net Billing Prior to Retail Access and Existing Arrangements</u>

The amended rule maintains the provisions of the existing rule for net billing prior to retail access. Thus, any existing arrangements and any new arrangements entered before March 1, 2000 would function as they do now. However, we have added a provision limiting new contracts to terms expiring no later than the initial date of retail competition. This is consistent with section 9 of the Act that provides that existing law and rules with respect to as-available energy be maintained until March 1, 2000. Additionally, no commenter presented any persuasive rationale supporting any change in the net billing rules prior to the implementation of retail competition.

For existing contracts that extend beyond retail access, we have added provisions that allow customers at their option to arrange for net billing arrangements with competitive providers. If the customer takes standard offer service, the standard offer provider(s) is required to provide service on a net basis and purchase any excess generation at the existing contract rates. The amended rule also requires T&D utilities to continue to bill both for their service and for standard offer service on a net basis. These provisions remain in effect throughout the duration of each existing contract. The additions are consistent with sections 5 and 8 of the Act that require contracts be maintained and that we adopt provisions that preserve the intent purposes of existing contracts. Requiring the standard offer providers to purchase any excess generation will avoid the need for the T&D utility to buy and then sell the energy in its section 3204(4) bid process. To address the concern raised by the Consolidated QFs, we have clarified that the provision on existing contracts governs only net billing contracts.

b. New Arrangements After Retail Access

The net energy billing provision was originally included in Chapter 36 as a means of reducing costs for very small QFs so their power could economically be sold to utilities. This was done by avoiding the costs of a second meter and, instead, using a single meter that registered power flows in both directions. The original rationale for net billing, however, is no longer applicable as we enter a restructured environment for several reasons. First, CMP has routinely installed a second meter for purposes of measuring usage for retail sales tax purposes so that the intended cost savings have not occurred.[19] Second, and more importantly, the concept of QFs' generating power and selling it to utilities at their avoided cost is rendered obsolete by a restructuring of the industry that allows for retail competition and restricts utilities from engaging in the generation and sale of electricity. We note that our changes to Chapter 36 are essentially to deal with the remnants of QF contracts and policies that extend beyond the initial date of retail access; when all existing QF contracts expire, there will no longer be any need for Chapter 36.

After considering the comments on this topic, we agree with Messrs. Talmage and Inoue and other commenters that net billing has become more than simply a way of reducing metering costs; rather, it has developed into a means of encouraging the use of small-scale renewable technologies designed primarily to serve the customer's own electricity needs. The promotion of such an outcome is consistent with legislative policies favoring renewable generation and energy efficiency. 35-A M.R.S.A. §§ 3210, 3211. As a result, our view is that a long-standing billing and metering practice that facilitates customers' abilities to meet their own loads through renewable resources is not a practice that should be eliminated solely as a result of industry restructuring. Instead, the practice should be modified so as to be workable in a restructuring environment.

For the reasons stated above, however, new net billing arrangements after the initiation of retail access

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[19]Earlier in this process and in other proceedings, CMP maintained that there were other reasons for installing two meters. CMP's current position is that the retail sales tax requirements is the reason for two meters.

should not be included in a rule governing QFs and their power sale relationships with utilities that will phase-out over time as existing contracts terminate. It is more appropriate that such a provision be included in a rule generally governing the promotion of renewable resources in a restructured industry. We therefore have not included in the amended Chapter 36 a provision for new net billing arrangements after the advent of retail access; we will instead include such a provision in our rule on renewable resources, that will be promulgated pursuant to 35-A M.R.S.A. § 3210. This provision will be designed to facilitate the use of small-scale renewable generation to serve customers' own needs.

The new net billing provision that we anticipate including in the renewable resource rule will be the annualized methodology, proposed by Messrs. Talmage and Inoue and supported by Mr. Lord and the Public Advocate, in which usage and generation are netted against one another on a rolling basis for a 12-month period. Under this approach, customers can store, or bank, their generation from month-to-month for one year. After the end of the year, neither the T&D utility nor any generation provider would be obligated to pay for any net generation from these customers.[20] This approach has many advantages. For example, the annual netting will facilitate certain renewable technologies (such as small hydro and wind power) whose output varies greatly over the year. The absence of any power sales removes any incentive to size facilities to generate more power than necessary to serve the customer's own electricity requirements. It also avoids the anomalous result of a T&D utility that is not in generation business actually paying a customer if excess power is generated. Finally, the approach will be relatively easy to administer and will avoid complexities involved in requiring the purchase of very small amounts of energy.

The specific aspects of the annualized net billing provisions that we intend to include in the renewable rule are discussed below. To qualify for net billing, a customer will have to employ one of the technologies or fuel types listed in section 3210 and have a maximum installed capacity of 100 kW or less. There is no need to reduce the capacity limit because the absence of the sale of power should ensure that facilities

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[20]The provider of generation service will obtain the value, if any, of any excess generation.

are installed to meet customer loads rather then for energy sales. Additionally, we would not restrict availability to residential customers; there is no reason to exclude small businesses that wish to generate their own electricity from taking advantage of net billing.

We will not limit net billing to the generation portion of the electricity bills, but will apply it to T&D charges only to the extent they are usage sensitive. This approach mirrors the results of a customer who invests in energy efficiency. Customers may use their own generation to offset the total price of electricity but must pay any fixed charges designed to cover the costs of T&D system to which the customer remains connected.

We will also include a provision similar to that for existing contracts that allow customers the option of voluntarily arranging for net billing from a competitive provider. If a net billing customer takes service from the standard offer, the provider(s) will be required to provide generation on a net basis.

Finally, we will maintain the current provisions that net billing customers will not be charged the costs of a second meter, if one is necessary,[21] and that net billing service will be pursuant to a Commission-approved standard contract.

To conclude, our intent is to include in the final renewable resource rule a net billing provision as described above. We will, however, include the provision in the proposed rule and obtain comments to ensure that the specific aspects of the provision are workable and to consider variations that might be more desirable.

F. Section 6: System Emergencies

The substantive provisions of this section were not changed in the proposed rule. CMP provided the only comment on this section, stating that it agreed with its content. We have adopted this section without any change from the proposed rule.

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[21]As with all costs, we expect utilities to explore any legitimate means to avoid the costs of the second meter.

G. Section 7: Commission Procedures

Section 8 of the Act requires the Commission to establish methods for determining any rates, terms, conditions of QF contracts, including long-term avoided costs, that are rendered impractical or impossible to perform or implement as a result of industry restructuring. In section IV(D) of this Order, we discussed above our method to establish long-term avoided costs. This section of the rule governs the establishment of other contract terms. Because such provisions may be varied and are likely to be contract-specific, the proposed rule included a procedure whereby the Commission would establish rates, terms, and conditions, consistent with the requirements of section 8 of the Act, as disputed issues arise.

Similar to existing practice, the proposed rule required the QF and utility to first attempt to resolve any differences over their contract terms. If, after good faith negotiations, the parties could not come to an agreement, either the utility or QF may file a petition for the Commission to establish the disputed term. In resolving the dispute, the Commission would make a finding that the disputed rate, term, or condition has been rendered impractical or impossible to perform as a result of industry restructuring. If it makes such a finding, the Commission, consistent with section 8 of the Act, would establish a rate, term, or condition that preserves the intent and purposes embodied in the original contract.

The proposed rule also deleted many of the detailed procedures currently contained in section 6 of the rule as either inapplicable due to industry restructuring or unnecessarily specific. The proposed rule did, however, maintain a general provision stating that the Commission may investigate, either as a result of a petition or on its own motion, any matter relevant to the provisions contained in the rule.

CMP provided the only comment on this section, stating that it agreed with its content. We have adopted this section without any change from the proposed rule.

H. Section 7 (existing rule): Commission Procedures Upon Petition to Issue Order Requiring Wheeling

Section 7 of the existing rule implements the affiliate wheeling section of Title 35-A, section 3182. The proposed rule deleted this entire provision because it has become obsolete with the enactment of the Energy Policy Act of 1992 and the Federal Energy Regulatory Commission's promulgation of its Open Access Rule, FERC Order No. 888. We received no comments on this section. The section is deleted in the amended rule.

I. Section 8: Small Electric Utilities

This section contains provisions and requirements regarding small electric utility purchases of power from QFs. The proposed rule added a provision specifying that this section would no longer be effective as of the date of retail access, because at that time utilities will no longer be under any requirements to purchase QF power. We received no comments on this section. We have adopted this section without any change from the proposed rule.

V. OUT YEAR AVOIDED COSTS

The Consolidated QFs, Benton Falls Associates (commenting separately) and RWS urged the Commission to acknowledge in this rulemaking that so-called "out-year" or "orphan decrement" avoided costs have already been established. This matter concerns language in certain QF contracts describing the rates for purchases for years in which avoided costs had not been determined at the time the parties executed the initial contracts. The QFs stated that they are not asking the Commission to resolve a contract dispute, but rather to state affirmatively the action the Commission took when it last set avoided costs for CMP.

We decline to address this matter for two reasons. First, this proceeding is a rulemaking docket opened for the explicit purpose of amending Chapter 36 in light of industry restructuring. The matter raised by the QFs involves existing contracts and is not related to either industry restructuring or this rulemaking. Second, although the QFs characterize their request as asking the Commission to state what it did in a past case, the request is in the nature of a contract interpretation to resolve a dispute. The official actions of the Commission are described in its written decisions. Any further description of what it did in a prior case would essentially include a consideration of whether rates have already been set for purposes of the contracts in question. In effect, this would involve contract interpretation.

It is unclear whether the Commission has jurisdiction to interpret or otherwise act to resolve disputes regarding existing QF contracts. It is clear that, if such jurisdiction exists, the current rulemaking is not a vehicle to exercise that jurisdiction.

Accordingly, we

O R D E R

1. That the attached Chapter 360, Cogeneration and Small Power Production, is hereby adopted;

2. That the Administrative Director shall send copies of this Order and the attached rule to:

A. All electric utilities in the State;

B. All persons who have filed with the Commission within the past year a written request for notice of rulemakings;

C. All persons on the Commission's electric restructuring service list, Docket No. 95-462;

D. All persons that provided comments in this rulemaking, Public Utilities Commission, Rulemaking Qualifying Facilities Rates, Terms, and Condictio in Restructured Electric Industry, Docket No. 97-794;

E. All persons that provided comments in the rulemaking, Public Utilities Commission, Bidding Processes and Terms and Conditions for Standard Offer Electric Service, Docket No. 97-739;

F. The Secretary of State for publication in accordance with 5 M.R.S.A. § 8053(5); and

G. The Executive Director of the Legislative Council, 115 State House Station, Augusta, Maine 04333 (20 copies).

Dated at Augusta, Maine this 10th day of March, 1998.

BY ORDER OF THE COMMISSION

Dennis L. Keschl (MB)

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Hunt

65 - INDEPENDENT AGENCIES - REGULATORY

407 - PUBLIC UTILITIES COMMISSION

CHAPTER 360 - COGENERATION AND SMALL POWER PRODUCTION

SUMMARY: This rule establishes the principles and procedures used by the Commission in setting rates for purchases of electricity from small power production facilities and cogenerators.

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§1 GENERAL PROVISIONS

A. Definitions. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA), Public Law 95-617, shall have the same meaning for purposes of this chapter as they have under PURPA, unless further defined in this chapter. In addition the following definitions apply for purposes of this chapter.

1. "Affiliate" means a person who:

a. Directly controls, is controlled by or is under common control with, a qualifying facility or industrial enterprise; or

b. Substantially owns, directly or indirectly, or operates, a qualifying facility or industrial enterprise.

2. "Associate" means:

a. An affiliate; or

b. A person that contracts to receive the thermal output of a cogeneration facility.

3. "Avoided costs" means the incremental costs to an electric or transmission and distribution utility of electric energy, capacity, load management, and/or conservation measures which, but for the purchase from the qualifying facility or qualifying facilities, such utility would obtain from another source. After the date of retail access, "avoided costs" mean the market value of the electric energy or capacity supplied by a qualifying facility to a transmission and distribution utility.

4. "Back-up power" means electric energy or capacity supplied by an electric or transmission and distribution utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

5. "Biomass" means any organic material not derived from fossil fuels.

6. "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for electrical power production.

7. "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for heating or cooling purposes, through the sequential use of energy.

8. "Energy input" in the case of energy in the form of natural gas or oil is to be by the lower heating value of the natural gas or oil.

9. "Existing contract" means a contract or an amendment to a contract executed prior to September 19, 1997 under which a qualifying facility sells energy or energy and capacity to an electric or transmission and distribution utility.

10. "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric or transmission and distribution utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, or industrial enterprise under section 7(A), including transmission or distribution of the qualifying facility's power to another utility's transmission or distribution system to the extent such costs exceed the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs. Interconnection costs shall also include an equitable portion of the cost of improvements to the utility's existing transmission and distribution facilities necessitated by the interconnection with a qualifying facility or industrial enterprise.

11. "Interruptible power" means electric energy or capacity subject to interruption by the provider of such energy or capacity under specified conditions.

12. "Maintenance power" means electric energy or capacity supplied by an electric or transmission and distribution utility during scheduled outages of the qualifying facility.

13. "Natural gas" means either natural gas unmixed, or any mixture of natural gas and synthetic gas.

14. "Net energy" means for any time period the total electrical energy used by a qualifying facility plus the total

electrical energy used by any related retail consumer of electricity located at the same site minus the total electrical generation of the qualifying facility.

15. "Net energy billing" means a billing and metering practice that uses a single meter, capable of registering the flow of electricity in two directions, to record net energy transactions between an electric utility and a qualifying facility.

16. "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum product.

17. "Parallel operation" means the synchronous operation of a utility's generating system with the electrical generating equipment of a qualifying facility.

18. "Person" means a corporation, partnership, limited partnership, business association, trust, estate, municipal or quasi-municipal entity, or natural person.

19. "Qualifying facility" means any small power producer or cogenerator which meets the criteria set forth in section 2 of this chapter.

20. "Rate" means any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

21. "Small electric utility" means any electric utility that is not an investor-owned electric or transmission and distribution utility.

22. "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility or only in the electric generation process of a bottoming-cycle cogeneration facility.

23. "Supplementary power" means electric energy or capacity, regularly used by a qualifying facility in addition to that which the facility generates itself.

24. "System emergency" means a condition on a utility system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

25. "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from electrical power production is then used to produce useful thermal energy.

26. "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful electrical power output and useful thermal energy output.

27. "Total energy input" means the total energy of all forms supplied from external sources other than supplementary firing to the facility.

28. "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the electrical power production process.

29. "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any process or used in any heating or cooling application.

30. "Variable operating and maintenance cost" means that portion of the operating and maintenance expenses associated with generating facilities which change with changes in the use of those facilities.

31. "Waste" means by-product materials other than biomass.

B. Exceptions. Upon the request of any person subject to the provisions of this chapter or upon its own motion, the Commission may deviate from the provisions of this chapter for good cause shown or to the extent it deems necessary to further the purposes and policies of this chapter.

§2 QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES

A. General Requirements for Qualification

1. Small power production facilities. A small power production facility is a qualifying facility if it:

a. meets the size criteria specified in § 2(B)(1);

b. meets the fuel use criteria specified in § 2(B)(2); and

c. meets the ownership criteria specified in § 2(D).

2. Cogeneration facilities. A cogeneration facility is a qualifying facility if it:

a. meets the applicable operating and efficiency standards specified in § 2(C); and

b. meets the ownership criteria specified in § 2(D).

B. Criteria for Qualifying Small Power Production Facilities

1. Size of the facility

a. Maximum size. The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

b. Method of calculation. For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydro-electric facilities, if they use water from the same impoundment for power generation. For purposes of making this determination the distance between facilities shall be measured from the electrical generating equipment of a facility.

2. Fuel use

a. The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 75 percent of the total energy input must be from these sources. Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

b. Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar-year period.

C. Criteria for Qualifying Cogeneration Facilities

1. Operating and efficiency standards for topping-cycle facilities

a. Operating standard. For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar-year period, be no less than 5 percent of the total energy output.

b. Efficiency standard. For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half of the useful thermal energy output, during any calendar-year period, must:

i) subject to § 2(C)(1)(b)(ii), be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

ii) if the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas or oil to the facility; or

iii) for any topping-cycle cogeneration facility not subject to subsection 2(C)(1)(b) there is no efficiency standard.

2. Efficiency standards for bottoming-cycle facilities

a. For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar-year period, be no less than 45 percent of the energy input of natural gas or oil for supplementary firing.

3. Waiver. The Commission may waive any of the requirements of paragraphs (1) and (2) of this subsection upon a showing that the facility will consume significantly less energy than would be consumed by the facility and the electric utility if the cogeneration facility were not constructed.

D. Ownership Criteria

1. General rule. Prior to the date of retail access, a cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power, other than power production facilities. After the date of retail access, a cogeneration facility or small power production facility may not be owned by a transmission and distribution utility or its affiliate unless permitted pursuant to 35-A M.R.S.A. § 3204(6).

2. Ownership test

a. For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by a public utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or public utility holding company has an ownership interest in a facility, the subsidiary's ownership interest shall be considered as ownership by an electric company or public utility holding company. For purposes of this section a company shall not be considered to be an "electric utility" company if it is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 14 U.S.C. 79c(a)(3), 79c(a)(5); or is declared not to be an electric utility company by rule or order of the Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935. 15 U.S.C. § 79b(a)(3)(A).

b. Any electric utility that owns any part of a qualifying facility shall maintain separate records for all income investment and expenses associated with its ownership, operation or management of the qualifying facility.

E. Exceptions. Notwithstanding any provision of this section any small power producer or cogenerator which is considered to be a qualifying facility by the Federal Energy Regulatory Commission shall be deemed to be a qualifying facility for purposes of this chapter.

§3 ADMINISTRATIVE DETERMINATION OF AVOIDED COSTS

A. Applicability. Except as otherwise provided, this section applies to each investor-owned electric or transmission and distribution utility in the State. This section shall remain effective until the date of retail access.

B. Energy and Capacity. Each electric or transmission and distribution utility shall submit the following pursuant to a schedule set by Commission order.

1. Avoided energy costs

a. The estimated avoided energy costs on the electric utility's system, for various levels of purchases from qualifying facilities. Except as provided in this subsection such levels of purchases shall be stated in blocks of not more than 50 megawatts for utilities with a peak demand of 500 megawatts or more, and in blocks equivalent to not more than 10% of the peak demand for utilities of less than 500 megawatts. At least two such blocks shall be provided. In the event that the utility can reasonably be expected to purchase an amount of energy at the rates established by the Commission pursuant to Section 4(C) which exceeds the amount of energy reflected in the first of the two blocks described above then the first block shall be stated in an amount equal to the reasonably anticipated purchases. The avoided costs shall be stated on a cents per kilowatt-hour basis (showing the same number of significant digits as were employed by the electric utility in its last Fuel Cost Adjustment tariff), during daily peak and off-peak periods, by month, for the most recent 12 months, and in each of the next 18 months or until the date of retail access if that date occurs within the 18 month period.

b. The utility's avoided energy costs shall include, as applicable, reasonable estimates of avoided fuel costs, avoided start-up costs, avoided variable operating and maintenance costs, and energy purchase costs.

c. In each estimate required by subparagraph (a) above, the avoided costs shall be calculated by determining the difference between the total electric energy costs estimated to serve a utility's load and the total electric energy costs estimated for that load reduced in every hour consistent with the block and time periods discussed above divided by the kilowatt hours reflected in such load reductions.

2. Avoided capacity costs.

a. The estimated avoided capacity costs on the electric utility's system, for various levels of purchases from qualifying facilities. Except as provided in this subsection, such levels of purchases shall be stated in blocks of not more than 50 megawatts for utilities with a peak demand of 500 megawatts or more, and in blocks equivalent to not more than 10% of the peak demand for utilities of less than 500 megawatts. At least two such blocks shall be provided. In the event that the utility can reasonably be expected to purchase an amount of energy and capacity at the rates established by the Commission pursuant to Section 4(C) which exceeds the amount of energy and capacity reflected in the first of the two blocks described above then the first block shall be stated in an amount equal to the reasonably anticipated purchases. The avoided costs shall be stated on a cents per kilowatt-hour basis (showing the same number of significant digits as were employed by the electric utility in its last Fuel Cost Adjustment tariff), during daily peak and off-peak periods, by month, for the most recent 12 months, and in each of the next 18 months or until the date of retail access if that date occurs within the 18 month period.

b. The utility's avoided capacity costs shall include, as applicable, reasonable estimates of avoided capacity construction costs, capacity purchase costs, and capacity sale values.

c. In each estimate required by subparagraph (a) above, the avoided costs shall be calculated by determining the difference between the total electric capacity costs estimated to serve a utility's load and the total electric capacity costs estimated for that load reduced in every hour consistent with the block and time periods discussed above divided by the kilowatt-hours reflected in such load reductions.

3. Supporting analyses and data. A copy of all analyses used to derive the estimates required by paragraphs (1) and (2) above together with all input data and a detailed description of the methodology used and all assumptions employed.

C. Commission Review. Material submitted pursuant to subsection B above shall be subject to review and approval by the Commission. In any such proceeding the utility has the burden of coming forward with justification for its data.

§4 ARRANGEMENTS BETWEEN ELECTRIC UTILITIES AND QUALIFYING FACILITIES

A. Scope

1. Applicability. This section applies to the regulation of sales and purchases between qualifying facilities and electric or transmission and distribution utilities, except as provided in section 8 below.

2. Negotiated rates or terms. Nothing in this rule limits the authority of any electric or transmission and distribution utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be established by this chapter; or affects the validity of any contract entered into between a qualifying facility and an electric or transmission and distribution utility for any purchase.

3. Generation or distribution for own use. Notwithstanding any provision of this chapter any small power producer or cogenerator may generate or distribute electricity through its private property or its associates' private property solely for its use, the use of its tenants, or the use of its associates without approval or regulation by the Commission.

B. Electric Utility Obligations

1. Obligation to purchase from qualifying facilities

a. Existing contracts. Each electric or transmission and distribution utility must purchase from qualifying facilities pursuant to the terms established in an existing contract, or, as applicable, pursuant to rates established by the Commission in accordance with this chapter.

b. Purchases not pursuant to existing contracts. Each electric or transmission and distribution utility shall purchase any energy which is made available from a qualifying facility at a price and under terms agreeable to the utility and the qualifying facility or at rates for short-term energy purchases as established by the Commission in accordance with the provisions of this chapter. The utility obligation to purchase energy which is made available from a qualifying facility at short-term energy rates shall remain effective until the date of retail access.

2. Obligation to sell to qualifying facilities. Prior to the date of retail access, each electric or transmission and distribution utility shall sell to any qualifying facility, in accordance with this chapter, any energy and capacity and transmission and distribution services requested by the qualifying facility, provided the qualifying facility is located within the utility's service territory. After the date of retail access, each electric or transmission and distribution utility shall sell to any qualifying facility any transmission and distribution service available to other retail customers requested by the qualifying facility, provided the qualifying facility is located within the utility's service territory.

3. Obligation to interconnect

a. Any electric or transmission and distribution utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales by any utility under this chapter provided, however, that no interconnection shall be made unless the interconnecting utility inspects the interconnection facility and determines that the facility:

i) complies with the requirements of the National Electric Safety Code;

ii) provides reasonable protection of the interconnecting utility's generating, transmission and distribution systems; and

iii) is designed to prevent a violation of the prohibition contained on § 4(C)(1)(c). The obligation to pay for any interconnection costs shall be determined in accordance with subsection F of this section.

b. No interconnecting utility may unreasonably refuse to inspect an interconnection facility nor may a utility unreasonably delay the performance of any such inspection.

4. Parallel operation. Each electric utility shall offer to operate in parallel with a qualifying facility.

C. Rates for Purchases

1. General Provisions

a. Rates for purchases shall:

i) be just and reasonable with respect to the customers of the electric or transmission and distribution utility and in the public interest; and

ii) not discriminate against qualifying cogeneration and small power production facilities.

b. Nothing in this section requires any electric or transmission and distribution utility to pay more than its avoided costs for purchases nor shall this chapter be construed to limit or otherwise discourage an electric or transmission and distribution utility or qualifying facility from negotiating any reasonable price or other contract terms agreeable to the utility and the qualifying facility.

2. Short term energy purchases

a. Prior to the date of retail access, with respect to purchases of energy made by electric or transmission and distribution utilities from qualifying facilities on an as available basis the rates established by the Commission shall equal the avoided energy costs determined in accordance with section 3 after consideration of the factors set forth in paragraphs 4 of this subsection.

b. For periods after the date of retail access, the Commission shall set rates in accordance with the following procedures.

(i) Filing. On January 15, 2000 and on January 15 of each succeeding year, each transmission and distribution utility that has a qualifying facility contract that contemplates Commission-established short term energy rates for the 12 month period beginning March of that year shall file rates with the Commission calculated as described in this subparagraph and serve copies of the filing on a predetermined service list. The short term energy rates shall be calculated as the sale prices accepted pursuant to the sale of the rights to the energy component of qualifying facilities contracts pursuant to 35-A M.R.S.A. § 3204(4) for each month during the 12 month period beginning March of that year. The short term energy rates shall be time differentiated for the same periods and expressed on a cents-per-kilowatt hour basis with the same number of significant digits as in short-term energy rates in effect as of January 1, 1997.

(ii) Procedure. Any interested person may object to the utility's proposed short term energy rates by demonstrating that the rates are not reasonably representative of short-term wholesale energy costs in Maine or are otherwise inconsistent with law. Objections must be filed by February 15. If no objections are filed, the short term energy rates shall become effective on March 1 unless suspended by the Commission or its Director of Technical Analysis. If an objection is filed, the Commission or its Director of Technical Analysis may suspend the filing. In the event the filing is suspended, the Commission will adopt procedures for establishing short-term energy rates.

3. Standard rates for energy and capacity purchases

a. Prior to the date of retail access, standard rates for purchases of energy by a utility will be established by the Commission in accordance with section 3 after consideration of the factors in paragraphs 4 and 5 of this subsection. These rates will be available to any qualifying facility with an installed capacity of 1,000 kilowatts or less that elects to sell energy as available and that has been unable to reach a negotiated price with the electric or transmission and distribution utility.

b. Prior to the date of retail access, standard rates for purchases of energy and capacity sold by a qualifying facility pursuant to a 5, 10, 15, or 18-year contract will be established by the Commission after review of the filing of avoided cost data filed by the utility pursuant to section 3 of this chapter and consideration of the factors in paragraphs 4 and 5 of this subsection. These rates will be available to any qualifying facility that has an installed capacity of 1,000 kilowatts or less that has been unable to negotiate a contract with the electric utility. Separate time differentiated rates shall be established.

c. Prior to the date of retail access, standard rates established pursuant to subsections (a) and (b) above will correspond to the blocks described in section 3. In determining whether the standard rates for a block have been committed and thus no longer available to qualifying facilities, the Commission will compare the total avoided cost associated with a block to the total estimated cost of the purchases from qualifying facilities that have executed contracts since the standard rates were established.

d. For periods after the date of retail access, the Commission shall set standard rates for purchase of energy and capacity sold by a qualifying facility with an installed capacity of 1,000 kilowatts or less in accordance with the following procedures:

i. Filing. On January 15, 2000 and on January 15 of each year following a new sale of the rights to capacity and energy of qualifying facility contracts pursuant to 35-A M.R.S.A. § 3204(4), each transmission and distribution utility that has a qualifying facility contract that contemplates Commission-established standard rates for purchases of energy and capacity shall file rates with the Commission calculated as described in this subparagraph and serve copies of the filing on a predetermined service list. The capacity and energy rates shall be calculated as the sale prices accepted pursuant to the sale of the rights to the energy and capacity components of qualifying facility contracts pursuant to 35-A M.R.S.A. § 3204(4) for each month beginning March 1 and continuing until the end of the sale period. The capacity and energy rates shall be time differentiated.

ii. Procedure. Any interested person may object to the utility's proposed capacity and energy rates by demonstrating that the rates are not reasonably representative of wholesale capacity and energy costs in Maine or are otherwise inconsistent with law. Objections must be filed by February 15. If no objections are filed, the capacity and energy rates shall become effective on March 1 unless suspended by the Commission or its Director of Technical Analysis. If an objection is filed, the Commission or its Director of Technical Analysis may suspend the filing. In the event the filing is suspended, the Commission will adopt procedures for establishing capacity and energy rates.

4. Factors affecting rates for purchases of energy. In determining rates for purchase of energy, the Commission may consider the following factors to the extent practicable.

a. The availability of energy from a qualifying facility during on-peak and off-peak periods.

b. The ability of the utility to dispatch the qualifying facility. If the utility is able to dispatch the output of the qualifying facility, without reducing the total energy production of the qualifying facility, the energy portion of the standard rates established by the Commission pursuant to paragraph 3(a) and (b) shall be increased 3 percent unless otherwise ordered by the Commission.

c. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities. If the utility is able to schedule the maintenance of the qualifying facility, the energy portion of the standard rates established by the Commission pursuant to paragraph 3(a) and (b) shall be increased 1 percent unless otherwise ordered by the Commission.

d. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility. Unless otherwise ordered by the Commission, the rates established for purchases from any specific qualifying facility shall be increased to reflect the same level of line losses as used to establish retail rates for any class of customer that is served at a similar voltage level.

e. The usefulness of energy supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation.

5. <u>Factors affecting rates for purchases of energy and capacity</u>. In establishing rates for the purchase of capacity and energy the Commission may consider the factors discussed in subsection 4 above and, in addition, may consider the following factors to the extent practicable.

a. The availability of capacity from a qualifying facility during on-peak and off-peak periods.

b. The expected or demonstrated reliability of the qualifying facility.

c. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

d. The individual and aggregate value of capacity from qualifying facilities on the electric utility's system.

6. When the Commission determines standard rates pursuant to this section, the Commission will aggregate qualifying facilities and treat them as one in considering the factors listed in paragraphs 4 and 5.

D. Periods During Which Purchases Are Not Required

1. Any electric or transmission and distribution utility which gives notice pursuant to paragraph 2 of this subsection will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities can reasonably be expected to result in negative avoided costs.

2. Any electric or transmission and distribution utility seeking to invoke paragraph 1 of this subsection must notify the Commission and each affected qualifying facility at least 48 hours prior to period described above. Such notice shall include a description of the operational circumstances, and the duration of the period.

3. Any electric or transmission and distribution utility which fails to comply with the provisions of paragraph 2 of this subsection or which unreasonably invokes the provisions of this subsection will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph 1 of this subsection not occurred.

E. Additional Services to be Provided to Qualifying Facilities

1. Prior to the date of retail access, upon request of a qualifying facility in the utility's service territory, each electric or transmission and distribution utility shall provide at reasonable rates:

a. supplementary power;

b. back-up power;

c. maintenance power; and

d. interruptible power.

After the date of retail access, upon request of a qualifying facility, each electric or transmission and distribution utility shall provide at reasonable rates transmission and distribution services.

2. The Commission may waive any requirement of subsection (E)(1) of this section if, after notice in the area served by the utility and after opportunity for a public hearing, Commission finds that compliance with such requirement will:

a. impair the utility's ability to render adequate service to its customers; or

b. place an undue burden on the utility.

F. Interconnection Costs

1. Obligation to pay. Each qualifying facility shall be obligated to pay all interconnection costs as defined in this chapter.

§5 NET ENERGY BILLING

A. Net Billing Prior to Retail Access

1. Customer Qualification. Any qualifying facility that has an installed capacity of 100 KW or less may at its option sell electricity to an electric utility on a net energy billing basis.

2. Rates. Net energy sales during any billing period shall be at rates established pursuant to section 4(C)(2).

3. Second Meter. Nothing in this subsection shall prohibit a utility from installing additional meters to record purchases and sales separately, provided, however, that no qualifying facility which elects to sell electricity on a net energy billing basis shall be charged for the cost of the additional meters or other necessary equipment.

4. New Contracts. Any qualifying facility that has an installed capacity of 100 kW or less may obtain a customer net energy billing contract pursuant to this subsection. Any such new contract must terminate on or before February 28, 2000. Except for the contract duration and rates, contracts entered pursuant to this subsection shall contain the terms identical to those in the utility's existing customer net energy billing standard contract. The terms of the standard contract may be

modified subject to Commission approval.

B. Net Billing Pursuant to Existing Contracts After Retail Access

1. Existing Customer Net Billing Contracts. Any qualifying facility that has an existing customer net energy billing contract on the effective date of this section shall be billed by the transmission and distribution utility on a net energy basis for the duration of the contract.

2. Generation Service After Retail Access. Any qualifying facility that has an existing customer net energy billing contract may obtain retail generation service on a net billing basis from any competitive electricity provider that agrees to provide service and purchase energy on such a net energy basis. If the qualifying facility obtains generation service from the standard offer, the standard offer provider(s) shall provide service and purchase energy on a net energy basis. If there are more than one standard offer providers in a service territory, each provider shall purchase net energy in the same proportion as its standard offer obligation.

3. Rates. If the qualifying facility obtains retail generation service from a competitive electricity provider, net energy during any billing period shall be purchased by the competitive electricity provider at rates agreed upon by the qualifying facility and the competitive electricity provider. If the qualifying facility obtains standard offer service, net energy during any billing period shall be purchased by the standard offer provider(s) at rates established pursuant to the existing contract.

4. Second Meter. Nothing in this subsection shall prohibit a utility from installing additional meters to record purchases and sales separately, provided, however, that no qualifying facility which elects to sell electricity on a net energy billing basis shall be charged for the cost of the additional meters or other necessary equipment.

§6 SYSTEM EMERGENCIES

A. Discontinuance of Purchases and Sales During System Emergencies. During any system emergency, an electric or transmission and distribution utility may discontinue:

1. purchases from a qualifying facility if such purchases would contribute to such emergency; and

2. sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§7 COMMISSION PROCEDURES

A. Petition For Establishing Rates, Terms, and Conditions

1. Filing. If after good faith negotiations a qualifying facility and an electric or transmission and distribution utility are unable to reach an agreement, the qualifying facility or utility may petition the Commission to establish any rate, term, condition or other provision of a contract that is rendered impractical or impossible to perform or implement as a result of the restructuring of the electric industry.

2. Contents. The petition shall include the names and addresses of the qualifying facility and the utility, a description of the rate, term, condition or other contractual provision for which the petitioner seeks Commission intercession, an explanation of why the rate, term, condition or other contractual provision has been rendered impractical or impossible to perform or implement as a result of the restructuring of the electric industry, a copy of the contract, and any Commission orders relevant to the intent and purposes of the disputed provisions.

3. Service. The petitioner shall serve a copy of the petition by regular mail or fax to the affected utility or qualifying facility.

4. Response. The affected utility or qualifying facility shall file a response to the petition within 7 days of receiving service.

5. Timing. The Commission shall issue an order resolving the issues raised by the petition within 90 days of filing.

6. Resolution. The Commission shall make a finding as to whether the disputed rate, term, condition, or other contractual provision has been rendered impractical or impossible to perform or implement as a result of the restructuring of the electric industry. If the Commission makes such a finding, it shall establish a rate, term, condition, or other contractual

provision that preserves the intent and purposes embodied in the disputed contractual provision(s).

B. Commission Investigation

The Commission at any time may initiate an investigation or any person may petition the Commission to initiate an investigation of any matters relevant to the matters contained in this Chapter. The petition shall contain an explanation of the scope of the investigation sought. The Commission shall determine within sixty (60) days of the filing whether an investigation shall be opened. If a Notice of Investigation is not issued within 60 days, the request is denied. If an investigation is opened, procedures set forth in subsection B shall be followed.

§8 SMALL ELECTRIC UTILITIES

A. Applicability. This section applies to each small electric utility. Except as specified, other sections of this rule shall not apply to small electric utilities. This section shall remain in effect until the date of retail access.

1. Wheeling utility. If a small electric utility agrees to wheel the power of a qualifying facility to another utility under terms mutually agreeable or as set by the Commission, the small electric utility shall be exempt from this chapter.

2. Non-Wheeling utility. If a small electric utility and a qualifying facility do not wish to wheel the qualifying facility's power, the small electric utility shall be subject to the conditions set forth in subsection B through D.

B. Availability of small electric utility system cost data

1. Information provided on request. Each small electric utility subject to subsection A, paragraph 2 shall upon request of any qualifying facility:

a. Provide comparable data to that required under subsection B of section 3.

b. With regard to an electric utility which obtains its requirements for electric energy and capacity primarily from another electric utility or utilities, the utility may, at its option, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

2. Failure to provide information on request. If any such electric utility fails to provide such information on request, the qualifying facility may apply to the Commission for an order requiring that the information be provided.

C. Groups of small electric utilities. Two or more small electric utilities may form a group for the purpose of negotiations with and purchases from one or more qualifying facilities when the formation of such a group facilitates such negotiations and purchases. When such a group is formed, for the purposes of this rule, the Commission shall consider it as if it were a single small electric utility.

D. Obligation to Purchase from Qualifying Facilities. Each small electric or transmission and distribution utility subject to subsection A, paragraph 2 shall purchase any energy which is made available directly to the utility from a qualifying facility at a price and under terms agreeable to the utility and the qualifying facility or as established by the Commission in accordance with the provisions of this chapter.

BASIS STATEMENT: The factual and policy basis for this rule is set forth in the Commission's Statement of Factual and Policy Basis and Order Adopting Rule, Commission Docket No. 97-794, issued on ___________________. Copies of this Statement and Order have been filed with this rule at the Office of the Secretary of State. Copies may also be obtained from the Administrative Director, Public Utilities Commission, 242 State Street, 18 State House Station, Augusta, Maine 04333-0018.

AUTHORITY: 35-A M.R.S.A. §§ 104, 111, 1301, 1306, 3301-3308; P.L. 1997, ch. 316, §§ 5, 6, 7, 8, 9.

EFFECTIVE DATE: This rule was approved as to form and legality by the Attorney General on _______________. It was filed with the Secretary of State on ____________ and will be effective on _______________.