

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 98-824

February 22, 1999

PUBLIC UTILITIES COMMISSION
Sale of Capacity and Energy of
Undivested Generation Assets;
Extension of Divestiture Deadline
(Chapter 307)

ORDER PROVISIONALLY
ADOPTING RULE AND
STATEMENT OF FACTUAL
POLICY BASIS

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

In this Order, we adopt provisional rules implementing 35-A M.R.S.A. § 3204(4) (sale of capacity and energy of generation assets and generation-related business activities that are not divested by investor-owned electric utilities) and 35-A M.R.S.A. § 3204(3) (extensions for divestiture for certain assets).

II. STATUTORY REQUIREMENT AND OVERVIEW OF RULE

Section 3204 of Title 35-A (Divestiture of Generation) is part of the Act to Restructure the State's Electric Industry ("Restructuring Act" or "Act"). P.L. 1997, ch. 316 (codified at 35-A M.R.S.A. §§ 3201-3217). Section 3204 addresses disposition of generation assets by investor-owned electric utilities and requires the Commission to conduct two rulemakings. Neither the statute nor this provisional rule applies to consumer-owned electric utilities, as defined in 35-A M.R.S.A. §§ 3201(6) and 3501(1).

We describe first the general structure of section 3204. Subsection 1 requires utilities to "divest" themselves of "all" generation assets on or before March 1, 2000, except for certain listed assets and activities. Subsections 1 and 4 allow investor-owned utilities to retain ownership and control beyond March 1, 2000 of certain assets and activities that are listed as exceptions in subsection 1; subsection 4 requires utilities to sell their rights to the output (the capacity and energy) from those assets and activities after that date. Subsection 4 requires the Commission to conduct a rulemaking to govern the sale of that output. The rulemaking is designated by section 3204 as a "major substantive rulemaking."¹

¹Major substantive rulemakings are subject to provisions requiring submission and review by the Legislature. 5 M.R.S.A. §§ 8071-72.

Subsection 3 of section 3204 allows the Commission to extend the statutory deadline of March 1, 2000 for generation assets and generation-related business activities that are subject to the divestiture requirement of section 3204(1). It requires the Commission to conduct an additional rulemaking implementing that subsection. The rulemaking required by subsection 3 is also a major substantive rulemaking.

Although the two rulemakings required by subsections 3 and 4 of section 3204 are separate, they are related because it is necessary to determine what a utility must do with the output of any generation assets that subsection 1 requires the utility to divest by March 1, 2000 if the Commission, pursuant to subsection 3, grants an extension to that deadline. While the statute is not explicit, for the reasons discussed in section V(B) below, we conclude that subsection 4 requires utilities to sell their rights to the capacity and energy from any assets that the Commission exempts from the March 1, 2000 divestiture deadline, just as those utilities must sell their rights to the capacity and energy from those assets (listed in subsection 1) that the Legislature has exempted from the March 1, 2000 divestiture deadline.

Sections 1 through 9 of the provisional rule address the sale of capacity and energy from all generation assets that do not have to be divested by March 1, 2000, whether the Legislature has exempted them from that deadline under section 3204(1), or the Commission has granted an extension to the deadline under subsection 3.

Section 10 implements the divestiture deadline extension provision of section 3204(3); it sets forth the procedure and substantive provisions for the granting of those exemptions.

III. PRIOR INQUIRY; GENERAL CONSIDERATIONS

Prior to commencing this rulemaking, the Commission conducted an Inquiry. *Public Utilities Commission, Inquiry on Procedures and Standards for the Sale of Rights to Energy and Capacity and the Granting of Extensions for Generation Asset Divestiture*, Docket No. 98-227. The Inquiry requested commenters to address several policy questions. Central Maine Power Company (CMP), Bangor Hydro-electric Company (BHE), Maine Public Service Company (MPS) and the Independent Energy Producers of Maine (IEPM) responded to those questions.

One of the most important questions in the Notice of Inquiry asked the extent to which the Commission should be "prescriptive" in setting forth the procedures and other requirements for the

sale of capacity and energy pursuant to section 3204(4). CMP and BHE tended to favor a prescriptive approach. Arguments favoring this approach noted that it was more certain, more objective, and minimized utilities exposure to being found imprudent in a subsequent proceeding. Others took a different tack. MPS stated that the rule should "simply establish administrative procedures and not attempt to structure the process," that doing so "runs the risk of not anticipating the particularities of any individual sale." The IEPM suggested that the rule should only establish deadlines and that utilities should be given flexibility to design their own bid processes.

The provisional rule attempts to establish certainty and definition to the processes, while including relative simple provisions that provide the flexibility needed to attract good bids. As in the case of bids to provide standard offer service, we particularly desire that the methodology for evaluating bids be simple and objective without being unnecessarily rigid.

IV. THE RULEMAKING AND DISCUSSION OF SECTIONS OF PROVISIONAL RULE

On November 3, 1998, we issued a Notice of Rulemaking on sale of capacity and energy of undivested generation assets, Chapter 307. Consistent with rulemaking procedures, we provided interested persons with an opportunity to comment on the proposed rule. We received comments from all of the parties who had commented on the earlier Notice of Inquiry and a letter from Regional Waste Systems (RWS) joining in the IEPM comments filed on December 11, 1998.

We discuss below the individual sections of the provisional rule:

A. Section 1 - Definitions

This section contains definitions of terms used in the rule. MPS commented that the proposed rule envisioned bids for energy and capacity but not for ancillary services such as spinning reserve. While it is not clear to what extent the resources being sold are able to provide valuable ancillary services, it is clear that if such services can be provided under the terms of the existing contracts between utilities and the asset's owners or operators, then those services should be included as part of the sale. Accordingly, we have added a definition of "Capacity and Energy" which explicitly includes ancillary services.

CMP noted that our proposed rule was developed in terms of power deliveries from specific facilities, even though certain contracts have been renegotiated to allow the seller the option of delivering power either from a specific facility or from the market. We have added a definition of "Facility" that makes certain that the rule applies equally to both forms of power delivery.

B. Section 2 - Applicability of Chapter

1. Section 2(A) - Utilities Subject to this Chapter

Section 2(A) states that this Chapter will apply only to investor-owned electric utilities and transmission and distribution utilities. This provision is consistent with 35-A M.R.S.A. § 3204 which applies only to investor-owned utilities and not to consumer-owned utilities as defined in 35-A M.R.S.A. §§ 3501(1) and 3501(6), respectively.

2. Section 2(B) - Capacity and Energy Subject to this Chapter

Section 2(B) describes the capacity and energy that must be sold pursuant to 35-A M.R.S.A. § 3204(4) and sections 2-9 of this Chapter. Section 3204(4) states that the rule adopted by the Commission shall require utilities to sell the "rights to capacity and energy from all generation assets and generation-related business activities, including purchased power contracts, that are not divested pursuant to subsection 1. . . ." Section 3204 (1)(A)-(D) lists the group of assets and generation-related business activities that are not subject to the general requirement of divestiture by March 1, 2000.

It would appear to follow that section 2(B) of this Chapter should incorporate the list of excepted generation assets and generation-related business activities from 35-A M.R.S.A. § 3204(1). We do not, however, include paragraph D from the section 3204(1) list (assets that the Commission determines are necessary for the utility to perform its obligations as a transmission and distribution utility). 35-A M.R.S.A. § 3204(4) states specifically that the output from that excepted category of assets is not subject to the sale of capacity and energy requirement.

In addition to the output from the three categories of assets incorporated from 35-A M.R.S.A. § 3204 (1)(A)-(C), the provisional rule includes one other category. As discussed above, 35-A M.R.S.A. § 3204(3)(and section 10 of this Chapter) allows the Commission to extend the divestiture deadline

of March 1, 2000 for any asset or generation-related business activity that subsection 1 otherwise requires the utility to divest, if the Commission "finds that an extension would be likely to improve the sale value of those assets on the market."

Subsection 4 of section 3204 does not specifically mention the output from assets whose divestiture date has been extended by the Commission pursuant to subsection 3. Nevertheless, it does state that investor-owned utilities must sell the output from all generation assets and generation-related business activities "*that are not divested pursuant to subsection 1*" (emphasis added). If an asset is not divested because the Commission has extended the subsection 1 deadline for divestiture, then it literally is "not divested pursuant to subsection 1." It also is most unlikely that the Legislature intended different policies for similar circumstances: that a utility would have to sell the output from the assets the Legislature exempted (under subsection 1) from the divestiture requirement, yet it would not need to sell the output when the Commission (pursuant to subsection 3) grants an exemption from the subsection 1 deadline. Finally, the fact that a transmission and distribution utility cannot itself sell the output to retail customers provides further support for our conclusion that utilities must sell the output from assets whose divestiture deadlines have been extended by the Commission pursuant to subsection 3.²

3. Section 2(C) -- Exception

²Section 3204(3) states that if the Commission grants an extension from the divestiture deadline of subsection 1, "the utility shall transfer to a distinct corporate entity by March 1, 2000 the generation assets to which the extension applies." As discussed below, we have included this requirement in section 10(B) because it is required by the statute. As a matter of policy, we do not believe the requirement is necessary because the transmission and distribution utilities cannot sell the output from such assets to retail customers in any event, and they must sell it pursuant to 35-A M.R.S.A. § 3204(4), as we interpret that subsection. In addition, no similar requirement applies to assets that are exempt from the divestiture requirement under subsection 1 itself. We therefore currently intend to propose to the Legislature that it repeal the "distinct corporate entity" requirement.

Section 2(C) was added to the provisional rule pursuant to a comment from BHE. Several years ago, BHE entered into a contract to provide power to UNITIL Power Corp. This power is currently being provided, in part, from BHE's entitlement to PERC. BHE requested that we make clear that the bidding requirements of this Chapter do not apply to power already being sold under a preexisting contract. The exception makes that point clear. We note, however, that it appears that BHE will have to seek an extension under 35-A M.R.S.A. § 3204(3) to avoid the requirement to divest the UNITIL contract as a generation-related business.

4. Section 2(D) - Extension of Divestiture

This provision specifies the application of divestiture extensions to this Chapter.

C. Section 3 - General Requirement for Sale of Capacity and Energy

Section 3 states the general requirement for utilities to sell capacity and energy from specified assets.

D. Section 4 - Conditions Applicable to Sales and Utility Renegotiations During Sale Periods

1. Section 4(A) - Renegotiations by Utilities of Contracts for Capacity and Energy

Section 4(A) states that a utility has a continuing right to renegotiate any contract or other entitlement under which it obtains capacity and energy, for the purpose of meeting its obligation to minimize stranded costs. However, no renegotiation is to be effective until the end of the current sale period unless: 1) the amount of power and the fuel source remains unchanged; or 2) the winning bidder consents to the renegotiation.

To meet their statutory obligation to provide just and reasonable rates (35-A M.R.S.A. § 301), utilities must make all reasonable efforts to minimize costs. Under the Act, electric utilities (after March 1, 2000, transmission and distribution utilities) must mitigate stranded costs. 35-A M.R.S.A. § 3208(4). Maine's investor-owned utilities on numerous occasions have renegotiated contracts with qualifying facilities to lower their costs. Section 3204(4) states that nothing in the subsection "prohibits a utility from renegotiating, buying out or buying down a contract with a qualifying facility in accordance with applicable laws."

In its Inquiry comments, CMP recognized its obligation to mitigate stranded costs, and stated that the rule should accommodate renegotiations, buy outs and buy downs. CMP also stated, however, that "once a winning bidder has been selected for a particular asset and for a particular duration, that sale should continue in effect for its full term."

There are countervailing considerations regarding either policy: if a renegotiation, buy down or buy out of a contract occurs during the period of a capacity and energy sale, but cannot become effective until the end of that period, stranded costs may not be directly mitigated to the maximum extent possible. On the other hand, if a contract between a utility and a QF may be terminated or renegotiated in the middle of a sale period under this Chapter, bidders may take that risk into account in their bid prices, with the possible result that the amount utilities receive for the energy and capacity will be lower and the offset to stranded costs will be smaller.

In our Notice of Rulemaking, we noted that it was not possible to evaluate these considerations with full confidence and sought comments. As between the two alternatives we laid out, allowing renegotiation subject to conditions or prohibiting renegotiation during the pendency of the sale, all parties supported allowing renegotiation, and we adopt this approach. In addition, BHE suggested that renegotiation should also be allowed if the purchasers of that capacity and energy are compensated for damages. However, BHE noted that it already negotiated or bought out its contracts so it is unlikely that this section of the rule would ever apply to it, and no other party favored such a provision. Accordingly, we have not incorporated BHE's suggestion into the provisional rule.

None of the commenters favored the option suggested in the Notice of having bidders provide two bids, one based on the assumption that renegotiation during the term of the contract would be allowed and another on the assumption that it would be precluded. Accordingly, we will not pursue that approach.

2. Section 4(B) - Subsequent Divestiture by Utilities

Section 4(B) addresses an issue that is similar to that addressed in section 4(A). As discussed above, 35-A

M.R.S.A. § 3204(1) requires investor-owned electric utilities, by March 1, 2000, to divest all assets and generation-related business activities other than those specifically listed as exempt in that subsection. 35-A M.R.S.A. § 3204(3), however, allows the Commission to extend that March 1, 2000 divestiture deadline. In our discussion of rule section 2(B) above, we concluded that if we grant such an extension, the output from the generation asset or generation-related business activity must nevertheless be sold pursuant to the requirements of 35-A M.R.S.A. § 3204(3) and sections 4-9 of this Chapter. Under section 10, the Commission will establish the length of the extension and will specify whether the utility must divest the asset or generation-related business activities on that specified date or whether it may do so on or before that date.

Section 4(B) states that if the Commission grants an extension from the divestiture deadline in 35-A M.R.S.A. § 204(1), the sale of the output from the excepted asset is subject to the obligation of the utility to divest the asset at or within the time specified in the Commission's order granting the extension. As a result, the sale necessarily is subject to the risk that the output from an excepted asset may not be available when the asset is divested. As discussed below, the Commission under section 10 can fashion an order granting a divestiture date extension so as to minimize the risk to a purchaser of the output.

Section 4(B) also states that purchasers are subject to the risk that the capacity and energy from the asset or generation-related business activity may not be available after the divestiture. Bidders may discount the value of the output from an asset that is subject to a divestiture deadline because the amount of time the output is available is short or uncertain or both. Bidders might apply a greater discount to output that may be available only for a short period, even if the length of that period is certain. The discount might be greater still if the asset can be sold at any time prior to the deadline established by the Commission, rather than only at a specified time. On the other hand, utilities may be better able to maximize the value if they are permitted to divest the asset at any time prior to the deadline rather than only on the date specified by the Commission. In fashioning a request for an extension, we expect that the utility will take these considerations into account, as will the Commission in determining both the extension date and whether a utility must make the divestiture effective on the specified date or may divest at any time on or before the specified date. The Commission may, if otherwise appropriate, order a divestiture

date that is the same as the end of a sale period for capacity and energy under this Chapter.

3. Section 4(C) - Risk of Non-Performance;
Damages

In the Notice of Rulemaking, we stated that purchasers would assume the risk of non-performance by the actual producers of power, and should, thus, be entitled to any damages which would be due to the utility as a result of that non-performance. CMP, BHE and IEPM commented on this matter at length.

No commenters disagreed on the two major principles of this subsection. First, the purchase contracts will entitle the purchaser to whatever amount of energy happens to be provided to the utility, not to a set amount of energy and/or capacity. The purchaser assumes the risk that the actual power flow may be more or less than expected. Second, because the purchasers are bearing that risk, they should be entitled to damages resulting from at least some forms of non-performance by the power producers.

There were several specific concerns raised, however. IEPM was concerned that the proposed rule, as drafted, could fundamentally change the nature of the original contract between the power producer and the utility by transferring to the purchaser under this Chapter the utility's contractual rights to damages. We agree with the IEPM that it is not desirable to transfer contractual rights from the utility to the purchaser. It is note our intent for this rule to change the contractual rights between the producer and the utility, or in any other way create or curtail contract rights that might otherwise exist.

The proposed rule stated that if there were a breach of the contract between the utility and the producer of power, and the utility received damages as a result, then the utility would simply turn these damages over to the buyer of the power. Several commenters objected to this pointing to the very different nature of the contract between the producer and the utility, and the contract between the utility and the buyer.

The contracts differ in at least three significant aspects. First, the two contracts cover different periods of time. The purchaser would only suffer damages during the remainder of its contract with the utility while the utility would suffer damages during the remainder of its contract with the producer. The utility/producer contract would typically cover a longer (and never a shorter) period of time.

Second, the prices in the contracts may be quite different implying that the actual damages incurred by the utility and the buyer would be correspondingly different. For example, in the event of a producer default, the utility might suffer no actual damages if the market price of power for the remainder of its contract is, or is expected to be below the contract price at which the utility is obligated to pay the producer. The purchaser, on the other hand, would determine damages by comparing the market price of power to the price which it is paying to the utility. It is quite conceivable that a default might result in damages to the purchaser but a windfall to the utility.

Third, where there are liquidated damages clauses in utility/producer contracts, these clauses would have been negotiated based on the parties' expectation of the level of damages at the time they originally entered the contracts. Given the dramatic changes in power markets in recent years, these clauses may have little bearing on the damages which a purchaser under this rule might face in the event of a default.

Another issue raised by commenters was that the Maine utilities will be offering different products to prospective bidders. For example, CMP has approximately 50 power purchase contracts in place. A prospective bidder for the output of this rather diverse portfolio might take some comfort from the fact that a default by any one of these suppliers would have a rather small effect on the overall portfolio. BHE, on the other hand, has far fewer contracts. In fact, approximately half of its purchases are from a single facility. MPS has only one contract. Thus, a bidder for BHE's or MPS's capacity and energy would presumably face a much more substantial risk than a purchaser of the output of CMP's contracts.

Because the portfolios of energy and capacity differ so much among utilities, it is difficult to fashion a single approach to damages which would clearly fit all situations. For example, a potential buyer may be relatively unconcerned about fluctuations in energy deliveries from a diverse portfolio, but very concerned if the portfolio is dominated by the operation of a few facilities. For this reason, section 4(C) of the provisional rule provides for options. A utility may include a provision whereby the purchaser has no recourse against the utility, and any damages paid by the producer are allocated among the utility and the purchaser on an appropriate pro rate basis.³ Although, a utility may propose a

³For example, for a complete default, a reasonable pro rata allocation may be a ratio of the time from the default to the end

different approach in the request for bids and accompanying standard contracts if it believes this would be desirable. For example, a utility might wish to compensate the buyer if actual capacity or energy deliveries dropped below a specified level.

E. Section 5 - Dates for Issuance of Requests for Bids;
Termination of Bidding Process

1. Section 5(A) - Initial Round

We have chosen August 2, 1999 as the date on which utilities should issue requests for bids. We believe that date is reasonably far in advance of the March 1, 2000 deadline for the sale of output from non-divested assets, without being so far in advance of that deadline that potential bidders will have difficulty assessing the value of the capacity and energy.

In the Notice of Rulemaking, we asked whether it would be advantageous to stagger the capacity and energy bids and the Standard Offer (Chapter 301) bids so that a party interested in both bids could learn whether it was successful in one and then use that information in developing its proposal for the other.

Upon further reflection, it appears that staggering the bids is not practical. For both bids, we have allowed two months for bids to be analyzed and the winning bid determined. Whichever auction comes first, this determination would have to be made well before the winning bidder finished structuring its bid in the latter auction so that it could determine how the results of the first auction influenced its approach to the second. In other words, for a staggered bid process to have any real effect, one bid would need to precede the other by at least three months. Since it is impractical to accelerate either bid process by three months, we will not be able to stagger the bids. Accordingly, we have not modified the timing of the bids from the proposed rule.

2. Section 5(B) - Subsequent Rounds

Section 5(B) requires utilities to issue their requests for bids for subsequent sales of capacity and energy on dates to be determined by the Commission. The rule allows the Commission to establish the length of subsequent purchase periods by order issued pursuant to the authority of this Chapter. The proposed rule stated that the second request for bids be issued

of the utility/purchaser contract divided by the time from the default to the end of the utility/facility contract.

on August 1, 2001. We modified the provision to provide maximum flexibility in the timing of future bid processes. We made corresponding changes in other provisions of the rule.

3. Section 5(C) - Additional Bidding

Section 5(C) addresses the possibility that an additional bidding process may be necessary either because a purchaser of energy and capacity defaults on its obligations or sufficient bids are not received in the first place. Under the rule, the Commission may order a new round of bidding and may waive certain bidding requirements if necessary.

4. Section 5(D) - Termination of Bidding Process

Section 5(D) states that when a utility's generation assets and generation-related business activities have been fully divested, no further bidding processes are necessary and the utility is no longer subject to this Chapter.

F. Section 6 - Requirements for Requests for Bids; Bidding and Sale

1. Section 6(A) - Asset Categories

Based on comments by CMP in the Inquiry, we proposed to allow bidders to bid separately for the output from various categories of generation assets. CMP suggested that renewable resources may have enhanced value because of the portfolio requirements of 35-A M.R.S.A. § 3210. CMP also stated that nuclear and Hydro Quebec Phase II entitlements have "unique characteristics." We continue to believe that bidders should have the opportunity to bid separately for the output from separate categories of assets.

We received a number of comments on this topic. The comments highlighted a fundamental tension. While everyone agrees that our overriding goal should be to maximize the value of the energy and capacity offered for sale, it is not entirely clear how best to achieve this end. On one hand, it is desirable to disaggregate the portfolio wherever there is reason to believe that certain types of generation are particularly attractive (or unattractive) to some bidders; for example, some bidders might be willing to pay a premium for sources that can be used to meet Maine's portfolio requirement or for sources which customers might find particularly desirable.

On the other hand, dividing the portfolio creates two potential problems. First, a bidder who wants a broad,

diverse portfolio might prefer to be awarded the full portfolio. If that bidder believed that some of the most desirable sources might be "cherry picked" out of the mix so that it would only receive the less desirable (or less diverse) sources, then the bidder would presumably reduce its bid or not participate. In addition, CMP was concerned that it might be open to an "after-the-fact prudency review" if it had discretion as to what subcategorizes should be used.

Based on these comments we have made several changes to the provisional rule. We have modified the list of categories. In doing so, we note that there presently appear to be two reasons a bidder might prefer certain resources. One is that there is evidence that some customers may prefer "renewable" resources. In California, for example, some residential customers appear willing to pay a premium for "renewable" resources. Maine's hydro-electric and biomass resources are similar to the types of sources which those customers seem to prefer. Given the current renewable portfolio requirement in Maine, it is desirable to segregate the other resources which qualify as "renewable" for purposes of complying with the portfolio requirement.⁴ In addition, we have broadened the provisional rule to allow other parties, in addition to utilities, to propose alternative categories.

The provisional rule now includes the following categories:

- 1) Hydroelectric and biomass sources;
- 2) Other sources which qualify as renewable under 35-A M.R.S.A. § 3210;
- 3) Nuclear entitlements;
- 4) Any other category proposed by the utility or other party and approved by the Commission; or
- 5) All other generation sources.

To deal with the possibility that some bidders may bid a higher price for the complete portfolio or specified combinations, we

⁴We note that the demand for "renewable" resources may have two bases. Suppliers will need renewable resources as defined by Section 3210 to comply with State law. At the same time, individual customers may, for their own reasons, prefer sources which they perceive to be "renewable". It is not clear at present whether customers will view, for example, a fossil-fired cogeneration unit as renewable simply because it qualifies as renewable under 35-A M.R.S.A. § 3210. For this reason, we have separated hydro and biomass from the other sources.

have modified the provisional rule to allow bidders to submit a single bid for two or more categories.

CMP's requested that its Hydro Quebec Phase II-related entitlements be listed as a separate category. Clearly, these entitlements provide both capacity and energy and are not included within any of the categories of assets which are exempt from the requirement. For this reason, if CMP does not divest these entitlements, it must seek an extension pursuant to 35-A M.R.S.A. § 3204(3). See *Central Maine Power Company, Divestiture of Generation Assets - Request for Approval of Sale of Generation Assets*, Docket No. 98-058 (Dec. 17, 1998). If the extension is granted, CMP would sell its HQ-related entitlement pursuant to this Chapter. CMP may seek to categorize these entitlements separately, if it is appropriate to do so, under section 6(A)(4) of the rule.

Section 6(A)(4) allows a utility, through the approval process for requests for bids, to propose that requests for bids list additional output categories. A request for bids could list the output from an asset whose divestiture deadline is extended as a separate category, if approved by the Commission, or could include it in the "all other generation sources" category.

2. Section 6(B)- Contents of Requests for Bids; Commission Approval, and Section 6(C)(2) - Bid Pricing

Chapter 360 of our rules contains specific requirements governing the establishment of rates for purchases from qualifying facilities (QFs). Specifically, Chapter 360 defines the diurnal periods for time-differentiation of short-term energy rates. Our proposed rule mirrored these Chapter 360 requirements so that the results of the Chapter 307 bid could be used directly in setting Chapter 360 rates.

Several commenters took issue with this approach. They argued that the Chapter 360 method of specifying prices was not the industry norm and that if these Maine-specific conventions were made part of the bid package then potential bidders might be discouraged from bidding. In addition, commenters argued that it would not be difficult to adjust the Chapter 307 bids that were structured consistently with the industry norm to accurately conform to the Chapter 360 definitions. As a result, we have modified the provisional rule with respect to the definition of peak and off-peak time periods and the convention for stating capacity prices.

Section 6 (B)(2)(c) of the provisional rule states that the on-peak period shall be Monday through Friday from 7 A.M. to 11 P.M. and the off-peak period shall be all other hours. This is the 5 x 16 (5 days a week, 16 hours a day) on-peak period that is the standard industry definition in the region. In contrast, our proposed rule defined the periods as those reflected in short-term energy rates in effect on January 1, 1997. As noted above, this was to accommodate provisions in Chapter 360. Several commenters pointed out, however, that the use of nonstandard definitions of peak and off-peak diurnal periods could discourage some bidders. Accordingly we have modified the provisional rule to reflect the standard region-wide, and will work with the parties to develop a simple methodology to convert the 5 x 16 rates to short-term energy rates expressed in the time periods required by statute.

Section 6(C)(2) now states that the bid price for the capacity component of the bid shall be stated in dollars per kilowatt-month rather than dollars per kilowatt-hour as was proposed. Again, this change makes the rule consistent with standard industry practice. Like the changes to the definitions of peak and off-peak, this change may require development of a methodology to convert the bids into a cents per kWh basis.

Section 6(B)(3) requires Commission approval of all requests for bids. That proposal is consistent with suggestions by CMP that the process be as certain as possible in advance of bidding, and that the Commission approve each utility's request for bids and its proposed standard contract. Approval and disapproval of requests for bids is delegated to the Director of Technical Analysis.

3. Section 6(C) - Bid Pricing

a. Section 6(C)(1) - Separate Categories

Paragraph 1 of subsection C allows for separate bids for each of the categories listed in the request for bids, as well as bids for combinations of categories.

b. Section 6(C)(2) - Separate Pricing of Capacity and Energy

Paragraph 2 of subsection C governs bids for capacity and energy. It requires separate prices for capacity (in kilowatts per month) and energy (in kilowatt hours) and for

peak and off-peak periods. This provision is consistent with our decision that after March 1, 2000, the bid prices for energy and capacity output under this Chapter will establish certain rates utilities must pay for QF power under Chapter 360. Section 4(C) of Chapter 360 requires two sets of rates be established: short-term energy rates (§ 4(C)(2)) and standard rates for capacity and energy (§ 4(C)(3)). Both must be established "pursuant to the sales prices" for the output that is sold "pursuant to 35-A M.R.S.A. § 3204(4)" and, therefore, this Chapter. The Chapter 360 provisions reflect our policy that rates for purchases from QFs by utilities should be based on market prices, and that market prices are best determined by the sales prices for capacity and energy that would take place pursuant to 35-A M.R.S.A. § 3204(4) and this Chapter.

3. Section 6(C)(3) - Other Categories

In our proposed rule, we included a section 6(C)(3) which governed bid prices for sources other than QF and other renewable resource power. This section is deleted because there is no longer any distinction between the bidding methods for QF and non-QF sources.

4. Section 6(C)(4) - Bid Increments

Section 6(C)(4) permits bids in increments of 20% of the total output, or any multiple of 20%, for each category, or combination of categories of output described in section 6(A). This is a change from the proposed rule which only allowed such partial bids for the largest category. We are making this change because, unlike the proposed rule, the provisional rule allows bidders to bid on combinations of categories.

While a bidder may bid as small an increment as 20% of any category, if the bidder bids any higher increment, it must also provide bids for each lower 20% increment. Requiring bids for all increments allows the Commission, if necessary, to require a utility to sell the output from renewable sources to multiple providers if we make a finding that unacceptable market concentration might otherwise occur (see section 7(E), below). It is possible that not all increment levels will be equally attractive to a bidder. The rule, therefore, allows bidders to provide different prices for each increment.

G. Section 7 - Selection of Bidders; Sale

1. Section 7(A) - Eligible Bidders; Bidding Requirements; Time for Filing Bids; Noncompliance

Section 7(A) states that bids must comply with all requirements stated in requests for bids (which are approved by the Commission) and that failure to comply with any material requirement results in disqualification. In our Notice of Rulemaking, we requested comments on whether the Commission should review any decision to disqualify a bidder. MPS recommended that we limit the time in which we would make such a review. The provisional rule states that we will make such a ruling within seven days whenever that is feasible.

2. Section 7(B) - Requirements Applicable to Utilities and Affiliated Competitive Providers

Section 7 (B) states that both utilities and their affiliated competitive providers are subject to the standards of conduct contained in 35-A M.R.S.A. § 3205(3) and Chapter 304 of the Commission rules.

3. Section 7(C) - Financial Qualifications of Bidders

Section 7(C) states in very general terms that utilities shall determine whether winning bidders are financially qualified to make the required payments for the capacity and energy they will purchase. We do not require utilities to establish in advance that all bidders are qualified, as such a requirement would require substantially more effort by utilities. We also do not prescribe criteria for determining whether a winning bidder is financially qualified. Utilities have had substantial experience buying and selling power, and should be capable of determining the ability of buyers and sellers to pay without relying on criteria in the rule.

CMP generally agreed with this approach but was concerned "that Section 7(C) could be read to require that utilities be 100% certain that all financial commitments be met for the entire term of the contract." Such a reading would be unreasonable, in our view. Utilities in Maine, and elsewhere, regularly enter into contracts of similar overall size and scope. For all such contracts, the appropriate standard is whether a utility's decisions with regard to the financial responsibility of the buyer are reasonable and prudent, not whether they are 100% certain. In fact, it is not difficult to imagine situations where a decision to achieve 100% certainty of financial responsibility would be *imprudent* because the costs of obtaining perfect certainty were high relative to the likely benefits.

BHE proposed that the Commission adopt very specific criteria for assessing the financial qualifications of bidders lest they be placed "at prudence risk with respect to the price obtained for the energy and capacity." BHE further states that this approach may create a perverse incentive for a utility to place greater emphasis on financial risk and less emphasis on bid price in selecting a successful bidder" since BHE believes that Chapter 307 "substantially eliminates the prudence risk with respect to the price for energy and capacity."

We do not accept BHE's proposal. First, utilities are more capable than the Commission in determining appropriate criteria for financial qualifications. They do so regularly. In addition, we do not agree with BHE's assertion that Chapter 307 unreasonably biases utilities toward avoiding financial risk and, as a result, accepting a low price for their entitlements. All Maine electric utilities, including BHE, are under a duty to mitigate stranded costs. We expect this duty will overcome any tendency to accept an unreasonably low asset price in return for unreasonably high financial assurance. Finally, even if we were to accept BHE's assertion that the rule could bias utility behavior, we would favor a rather different solution. If, in fact, we had removed all of the risks associated with the price at which entitlements were sold, the solution would not be to remove all the risks of assessing financial qualifications as well. Rather, the better approach likely would be to provide more flexibility, incentives, and disincentives to market the entitlements effectively, not to shield utilities from the economic consequences, whether good or bad, of their decisions.

4. Section 7(D) - Selection

Section 7(D) of the provisional rule states that a utility must select the winning bidder(s) by November 1, 1999, i.e., 4 months prior to the effective date of the sales. For subsequent rounds of bids, the Commission shall determine the selection date. Because the selection of the winning bidder(s) should be primarily a mechanical process, the November 1 date should allow sufficient time for utilities to determine the winning bidder(s), whether the winning bidder(s) is financially qualified, and to select another winning bid if the initial winning bidder(s) is not financially qualified.

We have changed the selection date from the December 1 date contained in the proposed rule and have added language specifying that utilities may not execute contracts until directed to do so by the Commission. These modifications are consistent with changes to the proposed rule, discussed below, that will allow the Commission an opportunity to review

the utilities' selections and order that bids be rejected if it is in the public interest to do so. We have also modified this provision to be consistent with changes, discussed above, that allow for bids on all resource categories or combination of categories.

To determine the winning bid(s), the utility must compare bids that are likely to contain different prices from month to month and by time of day. Under the rule, utilities will compare the present value of the monthly prices in each bid, using as the discount rate the utility's before-tax cost of capital (the amount that the utility must earn for a fair return and to pay the federal and state income taxes on that return).

To determine the present values of the rates proposed by each bid for different times of day during the month, utilities must multiply each bid price by the quantities in kilowatt and kilowatt-hours the utility obtained for each resource category during the same month of a recent test period. Section 6(B)(2)(d) requires that the request for bids provide that kilowatt and kilowatt-hour output information, and section 6(B)(2)(e) requires the request for bids to state the 12 months of output data the utility will use in the net present value calculation.

5. Section 7(E) - Effective Date of Sales; Length of Sales Periods

Section 7(E) establishes that the first sale period will be two years and that the Commission will establish the length of subsequent sale periods by orders it will issue two months prior to the issuance of subsequent requests for bids. We adopt an initial period of two years because a shorter period would provide little certainty for purchasers, and a longer period increases the risk of uncertainty of future market prices. BHE agreed with this approach in its comments.

6. Section 7(F) - General Principles Applicable to Determination of Financial Qualifications and Selection of Highest Bidders

Section 7(F) states a general standard of fairness and non-discrimination that utilities must follow, as well as the principle that utilities shall select winning bidders so as to

maximize the sale price of the capacity and energy and minimize stranded costs.

7. Section 7(G) - Market Power

Section 7(G) provides a process for determining whether a single bidder may purchase all of the renewable resource portion of the capacity and energy available under this Chapter. This provision states that if the Commission conducts a proceeding that addresses market power, and determines that an unacceptable level of concentration would occur, it may limit the percentage that any single purchaser may purchase under this rule. The provision also states that the Commission could, after finding in another proceeding that those entities possessed an unacceptable level of market concentration, limit the amount of renewable resource output that specified entities could obtain.

In our Notice of Rulemaking, we sought comments both on our proposed approach to market power and on an alternative whereby we would simply specify in the rule the maximum percentage that a single bidder could purchase. BHE, CMP, and IEPM all submitted comments indicating that they preferred the approach in the proposed rule to the alternative. They noted their beliefs (1) that the likelihood of a market power problem is small; (2) that there is no basis to set a maximum percentage at this time; and (3) that even if a market power problem did exist, there is no single maximum percentage which could reasonably be applied to all potential buyers. Based on these comments, we will adopt the provision contained in the proposed rule as drafted.

CMP did seek two clarifications. It noted that since each utility would conduct its bid process separately, an individual utility would have no control over the total amount of capacity a winning bidder might have if it were successful in two or more bid processes. CMP also expressed its belief that any percentage limitations should be determined prior to the winning bidder selection date. Both observations are reasonable. We will address them more specifically when and if we conduct a market power proceeding and find that limitations are necessary.

8. Section 7(H) - Submission of Information to Commission

Section 7(H) requires each utility, on or before November 1, 1999, to notify the Commission of its selection of winning bidders made pursuant to section 7(D). Utilities are also required to provide support for their selections, a summary

of the losing bids, and any grounds for which the utility believes a contract with a winning bidder may not be in public interest. This provision has been modified to be consistent with a new provision we added, discussed below, that allows the Commission an opportunity to review the bids to determine if there is any public interest reason for contracts not to be executed with selected bidders.

In our Notice of Rulemaking, we asked parties to indicate whether purchase contracts awarded under this rule would have to be approved by the Federal Energy Regulatory Commission and, if so, whether there would be sufficient time available to obtain that approval. BHE and CMP filed generally similar comments. They agreed that FERC approval was necessary and that they should seek such approval under a market based tariff. We have no reason to disagree. Finally, both agreed that there is adequate time available to obtain that approval, although BHE suggested that an initial filing go to the FERC in early 1999 while CMP appeared to suggest that a FERC filing could wait until the contract was awarded. In either event, the rule appears to allow adequate time.

9. Section 7(I)- Commission Review; Rejection of Bids

As indicated above, we have added a new provision that allows the Commission an opportunity to review the utility selections and order the rejection of bids.⁵ This would occur upon a Commission finding that stranded costs would not be reasonably mitigated by accepting the winning bids. In that event, the Commission may direct the utility to accept an alternative bid or sell the output in the regional wholesale markets.

We have added this provision to allow the Commission to address unforeseen circumstances. The requirement for Maine's large utilities to sell their capacity and energy interests in certain generation-related assets is part of a unique and historic process. Both here and with the decision to use a similar bid process to provide the electric generation of many Maine consumers under the standard offer, 35-A M.R.S.A. § 3212, we are relying on auctions and the increasingly competitive generation market to restructure the electric industry in Maine and to institute a fundamental change in the way Maine consumers buy electric power.

Although we are confident that this approach is sound, we recognize that the capacity and energy bid mechanism is

⁵Because this provision does not require specific Commission approval of the sale, FERC preemption issues should be avoided.

unprecedented; as such, the results cannot be predicted with any degree of certainty. Because the rule seeks to utilize markets which are immature, it is prudent to consider contingencies. Our concerns are short term in nature. As markets develop, the likelihood of market imperfections will be reduced. But in the meantime, competitive firms that bid for capacity and energy will do so in markets in which there is little experience, and in which the regional power markets and the likely cost and availability of transmission are both in flux. It is possible, therefore, that potential bidders will respond to these uncertainties by presenting relatively low bids or no bids on some resources categories. In this event, it may be in the public interest to reject the winning bids and allow utilities to sell the output into the regional markets until it is reasonable to conduct a new bid process. This provision provides the Commission the flexibility to direct this result.

10. Section 7(J) - Stranded Costs

Section 7(I) states the effect that the sales price of capacity and energy sold pursuant to this rule will have on determinations of stranded costs for utilities. In general, the sales price will be used in determining the utility's stranded costs for the generation assets and generation-related business activities whose output has been sold. The provision states, however, that the Commission may conduct a proceeding to determine whether the utility acted prudently in the conduct of its bidding and selection process and may adjust stranded costs accordingly. The rule establishes detailed bidding procedures, and selection of the winning bidder(s) is largely a computational exercise. There is little opportunity for utility discretion as to those matters. Utilities must, however, make efforts to attract a large number of high-quality bidders, and must exercise judgment under sections 4(C) - Damages, 6(A)(4) - Bidding Categories, and 7(B) - Financial Qualifications.

CMP, in its comments, noted that given the "prescriptive nature of the rule and the approval process for the bid package, it appears unreasonable to subject a utility to a separate prudence review." While we agree that the rule reduces the scope of a potential prudence review, we cannot take the further step of concluding today that no reasonable prudence issue could ever be raised in the future. Given this, we cannot rule out the possibility that such a review may be both reasonable and necessary at some point in the future. For example, if a utility were to reject a high price bid in favor of a lower price bid based on an imprudent decision that the high

price bidder was not financially responsible, a prudence review would be necessary.

H. Section 8 - Payment by Purchasers; Default

1. Section 8(A) - Payment

Section 8(A) requires purchasers to pay monthly, not later than 20 days after the close of the billing. The billing period will be established in the contract between the utility and the purchaser(s). The rule also allows for earlier payment if the purchaser and the utility agree.

2. Section 8(B) - Default

Section 8(B) addresses contractual defaults by the purchaser of the capacity and energy. The provision requires utilities to address material defaults using reasonable business practices and, thus provides utilities with discretion to react to such situations. The provision allows the utility to sell the output associated with a breached contract to an alternative purchaser or into the regional wholesale market without Commission review and approval as long as any contractual sales term does not extend into the next sale period provided for in the rule. Because the rule's sale period corresponds to the Commission's review of "adjustable" stranded costs pursuant to 35-A M.R.S.A. § 3207(6), utility actions in response to defaults would be unlikely to impact ratepayers. Ratepayers are more likely to be affected if a utility enters an alternative contract that extends past the time the Commission adjusts recoverable stranded costs; as a consequence, Commission pre-approval is required in such cases.

The proposed rule contemplated a much greater degree of Commission involvement in default situations. CMP commented that, although it generally agreed with the proposed rule's basic approach, it questioned the Commission's statutory authority to adjudicate contract disputes arising from existing contracts. Upon further consideration, we conclude that the Commission should not place itself in the middle of contract disputes nor should we direct the utilities' response in default situations. It is more appropriate for utilities, at least in the first instance, to determine how to address defaults using normal business practices. We have modified the rule accordingly.

I. Section 9 - Exception to Bidding and Sale Requirements

Section 9 restates the provision in 35-A M.R.S.A. § 3204(4) that if the Commission determines that output of generation-related business activities is necessary for the utility to perform its obligations as a transmission and distribution utility in an efficient manner, that output is not subject to the bidding and sale requirements of 35-A M.R.S.A. § 3204(4) and this Chapter.

J. Section 10 - Extension of Date for Utility to Divest Generation Assets

Section 10 implements 35-A M.R.S.A. § 3204(3). That provision allows the Commission to grant an extension of the March 1, 2000 divestiture deadline in section 3204(1) for specified generation assets or generation-related business activities. As discussed above, that extension authority is separate from the capacity and energy sale requirement of section 3204(4), and the Legislature required an additional rulemaking for section 3204(3). However, we have determined that the output from an asset whose divestiture date is extended must be sold pursuant to subsections 2 through 9 of this Chapter. We therefore have combined the two rulemakings in a single Chapter.

1. Section 10(A) - Procedure; Order

Section 10(A) contains the date by which a utility must request an extension of the divestiture deadline, the procedure for addressing the request, and what must be included in the Commission's order, if it grants the extension. The order must specify the extension date and whether the utility must divest the asset only on that date or on any date prior to the stated date. As discussed above, purchasers of the output of an asset or generation-related business activities whose divestiture deadline has been extended make that purchase subject to the risk that the divestiture will occur and that the output may not be available following the divestiture. The Commission may be able to mitigate that risk (and therefore enhance the value of the output) by specifying that an asset may only be sold on a specific date. Such a restriction might also reduce the value of the asset in the divestiture market, however. Conversely, an order allowing the utility to divest on any date prior to the extended deadline might have the opposite effects. Finally, we have added language specifying that utilities may seek additional extensions.

2. Section 10(B) - Transfer to Affiliates on March 1, 2000

If the Commission extends the divestiture deadline of March 1, 2000 for a specified generation asset or generation-related business activity, 35-A M.R.S.A. § 3203(3) requires the utility to transfer the asset or generation-related business activity to a "distinct corporate entity." Section 10(B) restates that requirement. As discussed, we do not see a need or purpose for the requirement and will propose that the Legislature repeal it. We have discussed that the Legislature intended that utilities must sell the output from all assets and generation-related business activities that are not divested pursuant to 35-A M.R.S.A. § 3204(1), whether the exemption is granted by the Legislature itself (in subsection 1) or the deadline is extended by the Commission (pursuant to subsection 3). If the utility must sell the output under a bidding system, there is little risk of self-dealing or anti-competitive behavior. In addition, the Legislature did not require a transfer to a separate corporation of those assets that are exempted from the divestiture deadline in 35-A M.R.S.A. § 3204(1). The ownership of those assets and generation-related business activities remains with the utility, although their output must be sold pursuant to 35-A M.R.S.A. § 3204(4) and sections 2 through 9 of this rule.

Both CMP and BHE supported our intent to seek a statutory change.

3. Section 10(C) - Obligation to Sell Capacity and Energy

Section 10(C) requires that utilities sell the output (capacity and energy) from a generation asset or generation-related business activity whose deadline for divestiture has been extended by the Commission pursuant to this section and 35-A M.R.S.A. § 3204(3). As discussed above, those sales are governed by sections 2 through 9 of this Chapter. We have added language specifying that the Commission may direct the utility to sell the output of asset into the regional wholesale markets until the output is sold to a purchaser or the asset is divested.

K. Section 11 - Waiver

Section 11 is the standard exemption or waiver provision that the Commission includes in most of its rules.

Accordingly, we

O R D E R

The Administrative Director shall send copies of this Order and the attached rule:

1. That the attached Chapter 307, *Sale of Capacity and Energy; Extensions for Divestiture of Assets* is hereby provisionally adopted;

2. That the Administrative Director shall submit the provisionally adopted rule and related materials to the Legislature for review and authorization for final adoption;

3. That the Administrative Director shall file the provisionally adopted rule and related materials with the Secretary of State;

4. That the Administrative Director shall send copies of this Order and 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 Rulemaking;
- c. All persons listed on the service list or who filed comments in the Inquiry, Public Utilities Commission, *Sale of Capacity and Energy; Extensions for Divestiture of Assets*, Docket No. 98-824;

5. That the Administrative Director shall notify all persons on the Commission's list of persons who wish to receive notice of all electric restructuring proceedings that the rule was provisionally adopted and is available upon request.

Dated at Augusta, Maine this 22nd day of February, 1999.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR:

Welch
Nugent
Diamond