ORDER NO. 02-772

ENTERED OCT 30 2002

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 139

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Annual Adjustment to Schedule 125 under the terms of the Resource Valuation Mechanism.	))))))))	ORDER

DISPOSITION: RESOURCE VALUATION MECHANISM FOR 2003 ADOPTED

SUMMARY

In this order, we address Portland General Electric Company's (PGE) first annual revision of its power supply costs under its Schedule 125. Schedule 125 was developed as part of a stipulation concerning power costs during PGE's general rate case last year. [1] Schedule 125 establishes an annual resource valuation mechanism (RVM) adjustment, which PGE must file on November 15 of each year and which is effective January 1 of the following year.

The RVM process is important to PGE customers, as it requires PGE to lower rates if its power costs decline. Without this adjustment, customers would not benefit from declining power costs until PGE makes a general rate case filing. In addition, the RVM filing provides customers more choices by establishing transition charges or credits for those who choose alternative energy supply options or direct access.

In its preliminary filing, PGE forecasted its 2003 power costs to be \$480.5 million. This amounts to a 37 percent decrease of \$286.3 million from the 2002 test year forecast used in PGE's rate case last year. Based on this initial projection, PGE's base rates drop by an overall average of about 10 percent, with a smaller percentage for residential customers and a larger percentage for business and industrial customers. [2]

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[1] *In the Matter of Portland General Electric*, Docket No. UE 115, Order No. 01-777 at Appendix D.

[2] Other rate changes not related to this docket are expected to offset this decrease on January 1, 2003.

In response to PGE's filing, the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB) and the Commission Staff (Staff) sought reductions to PGE's 2003 power cost estimate between $28 million and $38 million based on a variety of proposed adjustments. ICNU proposed several adjustments related to modeling changes to PGE's power forecast model called "Monet." CUB proposed changes based on modeling changes to Monet and reductions in the company's production costs. ICNU, CUB, and Staff all proposed reductions related to four high-priced power purchases PGE made in early 2001.

We have reviewed the components of PGE's net variable power costs and the adjustments the company made to Monet. Based on evidence in the record, we reduce PGE's variable power cost estimate by approximately $25.2 million and production rate base by $9.7 million.

The exact impact on customer rates will not be known until November 15, the date PGE will make its final Monet run that produces the RVM adjustment for 2003. While we are unable to calculate the impact of these disallowances will have on each customer class, we estimate an overall rate decrease of about 12 percent, instead of the 10 percent decrease projected by PGE.

PROCEDURAL HISTORY

On July 23, 2002, Michael Grant, an Administrative Law Judge (ALJ) for the Commission, adopted a procedural schedule for this docket. PGE, ICNU, CUB and Staff participated as parties.

After discovery and the prefiling of testimony, the parties waived cross-examination of witnesses and the ALJ admitted filed testimony and exhibits into the record. The parties filed opening and reply briefs to the Commission on September 23, 2002 and October 1, 2002, respectively, and made oral arguments on October 4, 2002.

Based on the record in the matter, the Commission makes the following:

FINDINGS AND CONCLUSIONS

Schedule 125 – Resource Valuation Mechanism

In PGE's last general rate case, PGE, ICNU, CUB, and Staff negotiated a power cost stipulation that, among other things, established a process to determine charges for PGE's energy services.[3] The stipulation, which we adopted in Order No. 01-777, uses a combination of market prices and the value of PGE's resources to set energy service rates. PGE first determines the market price of power using its most

[3] Fred Meyer Stores also participated in the development of the power cost stipulation, but did not intervene in this docket.

recent forward price curves. To forecast its net variable power costs, PGE uses a production cost model called Monet.

In addition to this market price, PGE annually credits or charges each customer with the positive or negative value of PGE's resources. This credit or charge is calculated from the RVM set forth in the company's Schedule 125. The RVM compares, by customer class, the total cost of power from PGE's long-term (Part A) and short-term resources (Part B) to the market price of an equivalent amount of power.

Schedule 125 requires PGE to file annual adjustment rates for Part A and Part B on November 15 of each year, to be effective for service on January 1 of the following year. PGE filed direct testimony and exhibits supporting its forecast of the 2003 RVM on July 1, 2002. On November 6, 2002, PGE will update the data inputs to the Monet model and incorporate any other changes that the Commission requires in this order. PGE will make the final Monet run, with updated forward curves for gas and electricity, on November 14, producing the RVM adjustment for 2003 on November 15, 2002.

Applicable Law

The RVM adjustment is a filing subject to ORS 757.210. As such, PGE has the burden of showing that the adjustment is fair, just and reasonable. Thus, PGE must submit evidence in support of its filing. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose any portion of the adjustment.

A question has arisen in this case regarding the application of the burden of proof in Commission proceedings. Citing a recent Commission decision, PGE states that the only items at issue are those that the parties and the Commission identify:

> When the parties review the company's filings, they identify the issues with which they are concerned. If a party does not propose a change in a particular item, or if the Commission does not raise the issue, the item is adopted when the Commission issues its final order.[4]

PGE is correct that, in this order, we will focus on the issues identified by the parties in testimony and briefs. The language cited above, however, should not be construed to alleviate PGE's burden of proving that all the costs included in its 2003 variable cost estimate are just and reasonable and appropriate to include in rates. The failure of any party to question a particular adjustment does not eliminate PGE's burden to support it. As we explained in docket UE 115:

[4] *In re PacifiCorp*, Docket No. UM 995, Order No. 02-469 at 7.

> [U]nder ORS 757.210, the burden of showing that the proposed rate is just and reasonable is borne by the utility throughout the proceeding. Thus, if PGE makes a proposed change that is disputed by another party, PGE still has the burden to show, by a preponderance of evidence, that the change is just and reasonable. If it fails to meet that burden, either because the opposing party presented compelling evidence in opposition to the proposal, *or because PGE failed to present compelling information in the first place*, then PGE does not prevail.[5]

DISPUTED ISSUES

I. Scope and Nature of RVM Proceeding

As a threshold matter, CUB raises two issues about the scope and nature of this case. First, CUB states that it understood the annual RVM update would simply involve updating a few data inputs related to the company's variable power costs. For that reason, CUB explains it was surprised when PGE proposed over 163 changes to Monet, many of which CUB alleges go beyond what was contemplated by the power cost stipulation. As an example, CUB notes that Schedule 125 limits hydro changes to "operating constraints imposed by government agencies."[6] However, PGE proposed several hydro adjustments not related to governmental operating constraints, including modifying the basic theory of modeling the average water available for power.

Although PGE subsequently removed all of its hydro related updates in its "simple" Monet update discussed below, CUB contends that many of the company's other proposed changes greatly expand the scope of the RVM updating process. CUB notes that PGE relies on the "applicable resource" update provision of Schedule 125 to justify over half of the 163 changes. In light of PGE's broad interpretation of the "applicable resources" provision, CUB contends that the Commission should also consider whether adjustments should be made to PGE's fixed power costs. CUB explains that the company's filing has made it clear that the RVM process is not simply a process to update variable power costs, but rather an examination of the company's overall power costs.

Due to the expanded nature of the docket, CUB also questions whether the process used in this docket is sufficient to ensure adequate review of all of the issues related to the RVM update. It explains that the parties had only five weeks to evaluate and respond to PGE's 163 proposed changes. CUB contends that this is a remarkably short time to investigate not only the reasonableness of PGE's proposed changes, but also whether other adjustments not proposed by the company are appropriate.

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[5] Order No. 01-777 at 6 (emphasis added).
[6] Order No. 01-777, Appendix D at 4.

ICNU shares CUB's concerns. Although ICNU believes that the UE 115 stipulation intended to limit the RVM update process to variable power costs, it agrees with CUB that PGE has greatly expanded the scope of the docket and that the Commission should address the company's fixed power costs as well. ICNU is also concerned about the limited time that the parties had to review PGE's filing and respond to it in testimony. ICNU contends that such an abbreviated process created an excessively heavy burden for intervenors with limited resources. If the annual review of PGE's RVM is to have any meaning, ICNU asks that the Commission establish a process that will allow extensive scrutiny of PGE's costs.

Staff interprets the update provisions of Schedule 125 to include the addition or deletion of resources, and adjustments in the use of resources during the service year that result from changes such as load forecast and market prices. Schedule 125 says "Part A [long-term resources] shall be based on the Company's most recent rate order, adjusted for service year."[7] The schedule further states, "The Part A and Part B revisions shall reflect updates to the following:

- Applicable resources;
- Market power purchases;
- Costs of fuel and transportation;
- Hydro operating constraints imposed by governmental agencies;
- Market power prices (including transmission to the Company);
- Transmission and ancillary services; and
- Retail load forecast."[8]

Staff does not read these provisions to include updates to generation rate base or fixed operation and maintenance (O&M) expenses of existing facilities. For that reason, Staff explains it did not conduct a detailed analysis of changes in gross plant investment, depreciation, deferred taxes, return, or fixed O&M expense. While Staff agrees with CUB that such an analysis would yield a more accurate calculation of PGE's long-term power costs, Staff believes the exercise to be outside the scope of the RVM update process.

PGE contends that the scope of this proceeding is limited under Schedule 125 to the examination of variable power costs. It argues that CUB's proposed adjustments relating to fixed costs are outside the scope of the changes considered in this annual RVM update. PGE adds that, even if the Commission were to consider CUB's proposed adjustments, a proper review of the challenged costs would show that customers would actually pay more, not less.

PGE also defends the RVM process used in this docket. It notes that it has kept Staff and other parties informed of updates and enhancements to Monet as part of the quarterly power cost adjustment updates. PGE has also provided a chronological

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[7] Order No. 01-777, Appendix D at 4. *Id.*
[8] *Id.*

reconciliation log of all changes and updates the company has made to Monet since the final UE 115 power cost run. PGE also highlights that five workshops were held with Staff, CUB, and ICNU to address the Monet model and updates to the data inputs. The workshops, which were held from April 22 to July 8, covered such topics as transmission, hourly price generation, load forecasts, plant availability factors, and hydro modeling. PGE concludes that the company has provided the parties sufficient time to investigate and evaluate the updates and enhancements PGE made to Monet.

Commission Resolution

As noted above, this is the first year that PGE has filed an annual adjustment to the transition charges that will be associated with the company's long-term and short-term resources for the next calendar year. It is clear to us that the signatories to the power cost stipulation in UE 115 had differing expectations about the RVM update process. Unfortunately, the language used in the stipulation offers the parties and the Commission little clarification.

Because Schedule 125 states that the cost of long-term applicable resources shall be adjusted for the service year, CUB contends that the review of those costs is not limited to any particular subset of costs. While PGE contends otherwise, CUB notes that several of the company's proposed adjustments appear to include fixed-cost components.

We share CUB's and ICNU's concerns that the scope of this docket was too vague. Given the ambiguity in the Schedule 125 language, we will consider CUB's proposed adjustments relating to fixed power costs. Our decision is limited to this docket, and is not intended to establish the scope of the annual RVM updates in future years. Rather, this decision is made to address uncertainty surrounding this docket and to recognize the limited time the parties had to respond to the proposed adjustments.[9]

Due to extra work on behalf of all parties and the Commission, we do not believe that the process or schedule used in this docket has undermined the review of PGE's filing or any conclusions reached in this order. We do not, however, want to repeat this process in future years. Accordingly, we clarify our expectations as to the scope and process of the RVM update for subsequent proceedings. First, the annual update of PGE's RVM should not be the equivalent of a generation rate case. Rather, it should be a proceeding to review PGE's net variable power costs. Second, the company should file proposed model enhancements and data updates for the 2004 RVM adjustment by April 1, 2003, to give interested parties and the Commission sufficient time for review. The only changes allowed after that time should be limited to updates for load forecasts, new power purchase or sales contracts, new fuel contracts, and forward prices for electricity and gas. The Administrative Law Judge for the 2004 RVM proceeding shall establish the schedule for these further updates.

[9] We note that the Commission was not immune from this compressed schedule. Because of PGE's need to make a draft Monet filing in early November, we had with just over three weeks from the parties' oral arguments to issue this order.

II. Power Purchase Contracts

As part of its forecast of net variable power costs for 2003, PGE includes the following short-term power purchases:

Counter Party	Amount and Type	Transaction Date
Morgan Stanley Capital Group, Inc. (Morgan Stanley)	25 MW Peak	January 29, 2001
Morgan Stanley	25 MW Peak	January 29, 2001
El Paso Merchant Energy, L.P. (El Paso)	25 MW Peak	February 23, 2001
Mirant Americas Energy Marketing, L.P. (Mirant)	50 MW Peak	May 23, 2001

Together these contracts provide 125 megawatts of on-peak delivery for calendar year 2003 at a megawatt-weighted average price of $85.40 per megawatt hour (MWh). This price exceeds current market prices by a substantial margin and refl residual effect of the volatile wholesale market that existed from mid-2000 to June 2001.

ICNU, CUB, and Staff all propose to disallow varying combinations of these four contracts and substitute the cost of the agreements with prices that better reflect current market conditions.[10] While e rationale for removing the contracts, all suggest a disallowance between $27 and $29 million.

Staff argues that PGE entered into these high price contracts before the market for 2003 power products became liquid. Consequently, Staff contends that PGE's decision to enter these contracts was imprudent and recommends a $28.8 million disallowance.

ICNU contends that PGE's variable power cost estimate should be reduced due to the company's failure to take aggressive steps to minimize the impact of the four high-priced power purchase contracts. ICNU identifies two potential remedies that PGE should pursue. First, ICNU contends that, like other western utilities with high-priced contracts, PGE could seek to reform the contracts either through renegotiation or by filing a complaint with the Federal Energy Regulatory Commission (FERC). Second,

[10] Staff proposes the removal of all four contracts, ICNU proposed removal of the El Paso, Mirant, and one of the Morgan Stanley contracts, and CUB proposed removal of the El Paso and both Morgan Stanley contracts.

ICNU believes that PGE should more aggressively explore termination of the Mirant contract based on provisions in the contract that require the parties to maintain certain credit ratings.

CUB argues that the Commission should disallow the contracts due to PGE's failure to reform the contacts and the company's knowledge of Enron's improper trading practices during the time period in which the disputed contracts were formed. CUB stresses that customers are dependent on a well functioning and open energy market and makes note of PGE's alleged knowledge of Enron's manipulation of the wholesale marketplace. We address each issue separately.

A. Prudence of Entering Contracts

Staff contends that PGE imprudently signed the four disputed purchases prior to the power market for 2003 achieving liquidity. Staff explains that a liquid market is a market where many buyers and sellers are conducting a large number of transactions. Staff adds that liquidity is necessary for markets to produce competitive prices and that, due to this fact, PGE's own guideline requires a 12 to 18 month advanced purchasing timeframe for short-term market purchases (purchases with delivery duration of one year or less). Staff notes that PGE explained this liquidity guideline in docket UE 115, PGE's last general rate case:

> We do not buy just to meet our expected load under average weather conditions. We buy conservatively, twelve to eighteen months ahead, to ensure that we have the capability to meet one or more standard deviations off of this expected load[.] *Our twelve to eighteen month purchasing time frame is based on the period over which markets are "liquid," i.e., a large number of buyers and sellers participate.*[11]

Staff contends that the market for 2003 power products was not liquid in early 2001. It points out that there were no similar transactions prior to January 29, 2001, the date that PGE executed the two Morgan Stanley contracts, and that there were only two other additional "like transactions" prior to PGE signing the El Paso and Mirant contracts.

Staff recognizes that, under certain circumstances, it may be appropriate for PGE to deviate from its advanced purchasing rule and make power purchases in a market that is not liquid. Staff argues, however, that PGE has not provided sufficient justification for its decision to do so with regard to the four contracts at issue here. Staff contends that, contrary to PGE's claims, the Northwest Power Planning Council (NPPC) was reporting improved power supply availability in 2003. Although a March 2000 report from the NPPC indicated an increasing possibility of power supply problems over each of the next few winters, Staff claims that the NPPC backed away from that report

[11] PGE/302, Pollock-Huntsinger/7 (emphasis added).

and that, by late 2000, the NPPC was saying that the outlook for power supply availability had significantly improved.

For these reasons, Staff contends that PGE's decision to enter into these contracts was imprudent. It recommends that the Commission replace the price of the disputed contracts with a price that PGE would have paid had it followed its guideline and waited to make these purchases when the markets were liquid.

PGE defends its decision to make the four disputed power purchases by emphasizing it has a legal obligation to provide reliable retail power to its customers at reasonable cost. For that reason, PGE explains that its power procurement policy is based on a number of objectives, including:

- To meet the retail demand;
- To ensure adequate reliability for customers;
- To consider market liquidity;
- To manage PGE's exposure to credit-risk from counter-parties; and
- To limit PGE's exposure to changes in market price of gas and electricity to pre-established financial limits.

Under these principles, PGE believed it was necessary to begin acquiring power for 2003 during the first half of 2001 for several reasons. At the outset, PGE notes that the wholesale market prices at that time were highly volatile to an unprecedented degree and the lack of new generation and California's deepening power crisis raised concerns about reliability. These factors, combined with the potential for worse-than-normal weather conditions led many to forecast a significant probability of power supply problems in 2003.

PGE relies heavily on two reports from the NPPC. In the first report, issued in March 2000, the NPPC studied the adequacy of the Northwest's power supply and made the following conclusions:

- Over each of the next few winters (the months of December, January, and February), there is a relatively high probability of one or more events in which generation supply is not adequate to meet loads.
- The probability of a generation shortfall reaches approximately 24 percent by 2003.
- The region would need an equivalent of 3,000 megawatts of new capacity to reduce the probability of a generation shortage to a more acceptable level. [12]

[12] Staff/105.

In the second report, issued in October 2000, the NPPC repeated its conclusions from the March report, and discussed the volatility of power prices experienced by the region in the summer of 2000. The NPPC concluded that the prices were symptomatic of an overall tightening of supply, and were exacerbated by a combination of unusual weather, poor hydropower generation, increased gas prices, and factors related to the design of California's market structure.

In addition, PGE contends that, in early 2001, it appeared that California might begin purchasing large amounts of long-term power. Given the size of California's energy markets, PGE feared that this could significantly increase prices and potentially create supply constraints. Finally, PGE asserts that buying early in 2001 enabled it to acquire power in small increments over a longer period of time, which spread the price risk over time and allowed the acquisition of additional power at lower prices.

PGE objects to what it terms as Staff's "liquidity theory" both as a matter of fact and policy. At the outset, PGE contends that Staff's liquidity theory is not the company's power purchasing rule. PGE explains that Staff's reliance on testimony in docket UE 115 is misplaced, as that testimony only described PGE's practice under normal conditions of buying power 12 to 18 months in advance. PGE maintains that the company has no hard-and-fast 18-month rule. In support, PGE points to other testimony in docket UE 115, where a PGE witness explained "[w]e execute contracts *from two years to two hours in advance of need*, consistent with PGE's risk management policies and the timing of changes in expected loads."[13]

In addition, PGE believes that Staff's liquidity theory, if adopted, would be bad regulatory policy. According to PGE, Staff's theory would limit the company's ability to make prudent power purchases and place reliability in jeopardy. The company does not believe that liquidity should trump other considerations, such as PGE's duty to serve, when circumstances justify acquiring wholesale power even when markets are not liquid.

PGE also claims that, contrary to Staff's assertions, the 2003 power market was liquid in early 2001. For wholesale purchases more than four months from delivery, PGE asserts that a market is considered liquid if the number of like trades "averages one or two trades over several days."[14] PGE argues that the evidence shows that there were numerous trades between January 25 and January 31 for the delivery of power in 2003.

For all of these reasons, PGE contends that its decision to fill a small portion of its 2003 power needs in the first half of 2001 was a reasonable and prudent strategy to respond to the documented and prevailing concerns about price volatility and market reliability. PGE maintains that its actions helped ensure that the company would be able to discharge its duty to provide service, while leaving a majority of its wholesale

[13] PGE/300, Pollock-Huntisinger/11 (emphasis added).
[14] PGE/400, Pollock-Lyman/11.

position unfilled. PGE does not believe that any of the disputed contracts should be excluded from the forecast of company's net variable power costs.

Commission Resolution

In reviewing the prudence of a utility's conduct, we examine the objective reasonableness of the company's actions. As recently explained in docket UM 995, we do not focus on the outcome of the utility's decision. Rather, we review the reasonableness of the actions based on information that was available or could reasonably have been available at the time of the action.[15] Thus, in this proceeding, we must determine whether PGE's actions and decisions with regard to the four disputed power contracts were reasonable in light of the circumstances existing at the time PGE entered into the contracts.

It is important to note that, in a prudence review, the Commission must exercise a high degree of caution. We recognize the need for regulatory certainty, and, consequently, must use a high standard when examining the reasonableness of a utility's actions. We cannot let the luxury of hindsight allow us to second guess a utility's conduct. Moreover, we acknowledge the possibility that a prudently-made decision might turn out to be the wrong decision. Therefore, as stated above, we must look to the existing circumstances surrounding the decision, not the ultimate outcome of the decision.

Here, it is undisputed that PGE's decision to purchase 2003 power in early 2001 was unusual. Despite the parties' arguments about the nature of PGE's power procurement policies, PGE acknowledges that, since the mid-1990s, the company's general practice has been to purchase power 12 to 18 months ahead of the calendar year. In this case, PGE entered the four disputed contracts outside that window, making two purchases some 23 months in advance, with the two others occurring 22 and 19 months prior to delivery.

In addition, we find that PGE made the purchases before the market was liquid. As PGE explains, market liquidity is a function of the number of like transactions conducted during a relevant time period.[16] PGE defines "like transaction" as a transaction within the region, available to PGE for forward delivery during a similar time frame. For our purposes here, we interpret that definition to exclude all trades made outside the Pacific Northwest region for periods other than 2003.[17]

[15] *In re PacifiCorp*, Order No. 02-469 at 4.

[16] PGE/400, Pollock-Lyman/10.

[17] In its reply brief, PGE disputes the exclusion of transactions with destinations points other than the Mid-Columbia (Mid-C) trading hub. The only other destination points reported for 2003 power purchases, however, are Palo Verde and North Path-15. *Id.* While trades with other, more proximate destination points, such as the California-Oregon Border (COB), might also be included in the list of "like transactions," we cannot construe PGE's own requirement that the transaction be "within the region" to include trading hubs located in Arizona and central California, respectively.

Turning to the evidence, we find that, of the 42 power trades reported during the last week of January 2001, only six transactions were for 2003 power in the Pacific Northwest region.[18] We reduce this number to four to recognize the fact that two of the transactions on January 29 were actually PGE's purchases from Morgan Stanley.[19] Thus, contrary to PGE's assertions, there were not "one or two trades over several days" prior to the advanced purchases. Instead, there was just one like transaction prior to the date PGE signed the two Morgan Stanley deals. There were four like transactions prior to PGE signing the El Paso and Mirant contracts in February and May 2001, respectively.[20] So few transactions do not constitute a liquid market even under PGE's own definition.

Our findings that PGE made these purchases outside its own purchasing guidelines and in a non-liquid market, however, are not dispositive on the issue of prudence. We recognize that PGE's 12 to 18 month advanced purchasing benchmark is not a hard and fast rule, and that circumstances might support PGE beginning to make short-term purchases outside that guideline. Indeed, PGE reports that, in some instances, it purchased power more than two years in advance of need. Moreover, situations might arise that would make it appropriate for PGE to make power purchases in a non-liquid market. Therefore, we must examine whether the prevailing market conditions justified PGE's decision to enter into these contracts.

We share PGE's opinion that the wholesale market during early 2001 was simply "nuts" and recognize the challenge the company faced in securing adequate supplies for its customers. The unprecedented nature of the markets, however, does not relieve PGE of its burden to establish that it acted reasonably in responding to those conditions. While PGE relies heavily on two reports from the NPPC to supports its actions, the company overlooks several key facts underlying the NPPC's conclusions.[21] In the March 2000 report, the NPPC conditioned its conclusions on the assumption that no additional generating resources would be added to the system. In fact, the NPPC expressly stated that it was not fully confident of its conclusions: "It may be that very high prices during periods of short supply could result in more development [of new generation] or development of a different type than our analysis suggests."[22]

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[18] *See* PGE 403/Pollock-Lyman 1 and 2.

[19] Staff would further exclude transactions for off-peak or flat delivery, since the disputed contracts are for on-peak delivery.

[20] Given the timing of these deals, it is questionable whether the cited trades from the end of January properly constitute like transactions during the "relevant period." Indeed, PGE acknowledges that the wholesale power market could be liquid for days or weeks at a time, and then become illiquid. PGE/400, Pollock-Lyman/10. The company provided no additional evidence, however, relating to the liquidity of the market in the days and weeks leading up to its power purchases in February and May 2001.

[21] Staff also cites a third NPPC report, issued in March 2001. We share PGE's opinion, however, that this report should not be used in our prudence review. First, as PGE notes, the report was issued in March 2001, after PGE had signed three of the four power contracts. Second, the report expressly states: "This paper does not focus on conditions beyond 2001, and no inferences regarding the future adequacy and reliability of power supplies should be drawn beyond this time frame. Staff/106 at 2.

[22] *Id.*, at 5.

This caveat becomes more significant after the NPPC's October 2000 report. There, the NPPC took note of the very high prices that had occurred that summer during periods of short supply—the exact event that diminished its confidence in its earlier report. With these higher prices, the NPPC noted that new power plants not considered in the earlier report had begun construction. The NPPC added that 1,276 MW of new capacity would come on line by 2002, another 1,291 MW were being actively developed, and another 3,060 MW had begun the siting process. The NPPC concluded that this degree of new generation developer activity was encouraging.

While not eliminating the NPPC's concerns, this increased generation development improved the outlook for power supply availability in 2003. These potential new resources represented a significant amount of the 3,000 MW of supply that the NPPC earlier concluded was needed to lower the risk of generation shortages to an acceptable level. The addition of new capacity would also help stabilize prices to more familiar levels.

More importantly, the NPPC's reported concerns about power supply problems were expressly limited to the "next few winters," which the NPPC defined as "the months of December, January, and February.[23] Thus, the NPPC's prediction of a generation shortfall for the 2003 winter applied only to the period from December 2002 through February 2003. PGE, however, obligated itself to pay higher than market costs during 10 months of 2003 in which the NPPC gave no indication of power supply problems.

While it is a close call, we conclude that, based on the totality of the circumstances that existed in early 2001, PGE acted prudently in purchasing advanced power for the winter months of 2003. The NPPC's concerns about the availability of wholesale power during that period, combined with the overall market volatility and news that California might begin purchasing large amounts of long-term power, reasonably prompted PGE to buy power to help ensure adequate reliability for its customers during the winter of 2003.

We further conclude, however, that PGE has failed to establish the reasonableness of its decision to purchase high-priced power for the remainder to the 2003 calendar year. As stated above, concerns about supply availability in 2003 were confined to the winter months, not the entire calendar year. Moreover, prior to signing the contracts, PGE knew or should have known that the power market situation was improving due to increased development of generation facilities.

We also emphasize that PGE provides little if any supporting evidence relating to the price trend for 2003 power products or internal company analysis of that advanced market to justify its decision. The record reveals that, in the weeks prior to PGE's decision to sign the two contracts with Morgan Stanley, there was only one transaction for 2003 power products made in the region. PGE presents no evidence

[23] Staff/105 at 3.

related to market activity just prior to the other power purchases in February and May 2001. In the absence of more complete information and analysis of the market conditions for 2003 power, we have no basis to evaluate the reasonableness of PGE's business decision to buy high-cost power during 10 months in 2003 in which there was no indication of power reliability problems.

Accordingly, we agree, in part, with Staff's recommendation to disallow the disputed contracts. Based on the concerns about availability of wholesale power during the winter months of 2003, we will not disturb PGE's decision to secure a portion of its purchased power needs for the months of January and February 2003. The remaining 10 months of those contracts, however, should be repriced to more appropriate levels.

Staff recommends two proxy prices for this purpose. In its primary recommendation, Staff uses the price from PGE's earliest on-peak transaction that the company signed within its normal period for advanced purchases. PGE executed this purchase on October 21, 2001, well within its 18 month purchasing benchmark. As an alternative, Staff proposes a proxy price based on the average on-peak 2003 price from PGE's forward curve used in its July 27, 2001 Monet run filed in docket UE 115. Staff explains that this alternative proxy price reflects the market price prevailing at the start of PGE's 18 month purchasing guideline.

We find Staff's alternative proxy price most reasonable. The proxy price should be based on what PGE would have actually paid if it had prudently waited for the market to become liquid. While the record contains no specific evidence from which we can determine when, in fact, the market for 2003 power products became liquid, we conclude that PGE's advanced purchasing benchmark to be a practical estimate. As PGE itself explains, short-term power markets tend to become liquid some 12 to 18 months prior to delivery. We reject PGE's price cap of $91 per MWh established by FERC. As PGE itself recognizes, FERC established the price cap for real time and prescheduled daily trades, not for 2003 calendar year deals. Moreover, as Staff explains, the price cap simply sets an upper bound to what PGE would have paid.

In light of these decisions, we calculate a disallowance for the last 10 months of the four disputed contracts by taking the sum of the difference between the contract prices and Staff's alternative proxy price. This results in a $14.65 million reduction to PGE's net variable power cost estimate.

B. Reforming the Contracts

ICNU and CUB contend that PGE has not seriously sought reformation of the disputed power contracts. Both note that several other western utilities, including PacifiCorp, Sierra Pacific Power Company, and Nevada Power Company, have filed complaints with FERC seeking relief from similar above-market contracts. Some of these contracts involve Morgan Stanley and El Paso. In addition, the California Public

Utilities Commission (CPUC) has asked FERC to abolish over 30 different contracts with 23 different sellers. ICNU adds that FERC is taking these claims seriously, as evidenced by the agency's decision to hold full evidentiary hearings.

ICNU and CUB further contend that there is no evidence that PGE has pursued renegotiation of the contracts as an alternative to filing a complaint with FERC. ICNU notes that FERC has strongly encouraged all parties involved in such disputes to seriously explore settlements, and that several power suppliers have renegotiated power contracts. CUB highlights that FERC recently announced that it had reached settlement between five energy sellers and the State of California to reprice power purchase contracts.

ICNU and CUB suggest that PGE may not be pursuing relief at FERC due to inherent conflicts of interest resulting from its ownership by Enron. ICNU points out that Enron Power Marketing, Inc., (EPMI), a subsidiary of Enron, is a defendant in FERC proceedings. An attempt by PGE to reform the disputed contracts would conflict with EMPI's attempt to defend against similar claims. ICNU also notes that FERC is currently investigating PGE's role in alleged attempts to manipulate the Western power markets in 2000 and 2001. ICNU speculates that PGE may be reluctant to ask FERC to grant the company relief from contracts formed during that period. ICNU emphasizes, however, that these concerns do not relieve the company from its obligation to minimize excessive power costs on behalf of ratepayers. If PGE is unwilling to act in the best interests of its ratepayers, ICNU requests the Commission exercise its regulatory authority to ensure that customers are protected.

CUB specifically criticizes PGE's knowledge of Enron's trading practices that manipulated market prices and played a large role in the Western energy crisis. CUB notes that, in 2000, FERC was refusing to intervene because it had no evidence that anything other than supply and demand was affecting the market. CUB contends, however, that transcripts of conversations between PGE power schedulers show that, as early as April 2000, PGE knew that Enron was running a "scam" and using questionable trading tactics such as "ricochet" and "that wacky, double flip-over thing."[24]

CUB maintains that PGE's customers rely on the company working to ensure that the wholesale power markets are open, fair, and transparent in order that the markets produce competitive prices. CUB believes that PGE failed to protect these customer's interests by failing to alert FERC of Enron's tactics. Had PGE shared with FERC its knowledge of market manipulation, CUB claims it is likely that FERC would have acted sooner and the disputed contracts would not have been priced so high.

Staff did not pursue this issue as strongly as ICNU and CUB, but agrees that PGE should pursue rate relief from the disputed contracts under Section 206 of the Federal Power Act. Staff is not convinced by PGE's arguments that a FERC complaint would have negative effects on the company and its customers.

[24] CUB/115.

PGE maintains that it has analyzed and weighed the risk and benefits of filing a FERC complaint, and concluded that to do so could harm PGE and its customers. It contends that such an action would increase the company's costs by providing independent power producers and marketers the incentive to charge an additional risk premium for future transactions. PGE also believes that these parties may simply decide not to deal with PGE, limiting the number of trading partners willing to work with the company.

PGE also contends that an attempt to reform the power sales contracts would deter potential investors from developing new generation. It maintains that a FERC complaint would cause a loss of confidence in the market and dampen the incentive to invest in new generating resources at exactly the wrong time.

Furthermore, PGE claims that seeking relief would require PGE to undermine its position in FERC's pending review of 2000-2001 power sales in the Pacific Northwest. PGE explains that the company and its customers benefited from a number of advantageous power sales in early 2001, and that an adverse ruling in that case would require PGE to pay refunds and harm customers. PGE also points out that a federal ALJ has already determined that the Pacific Northwest power market in early 2001 performed as a competitive market and has recommended dismissal of the proceeding.

According to PGE, these considerations, taken together, show that a FERC complaint would create significant long-term risks for customers. Furthermore, the short-term benefits of such action, in contrast, are speculative and small. PGE claims that FERC is reluctant to disturb the sanctity of contracts, and that it has not yet set aside or reformed a single contract since the onset of the energy crisis. It adds that this Commission apparently shares that view, and has urged FERC to focus on prospective, not retroactive, relief.

PGE also clarifies that there are only a few Western utilities that filed complaints at FERC challenging term power contracts based on the energy crisis. In addition to the three utilities listed by ICNU and CUB, PGE cites five others, for a total of eight. PGE states that this is only a small fraction of the utilities that could have sought FERC relief. PGE also denies any conflict of interest due to Enron's ownership of the company. PGE points to unchallenged testimony that directly denied that Enron influenced PGE's management of the disputed contracts.

Finally, PGE contends that ICNU's and CUB's proposed remedy is unjustified, as it assumes that success at FERC is guaranteed and that FERC will reform the contracts to current market levels or to the average price for all other PGE contracts for power in 2003. This has led ICNU to suggest a $29.7 million adjustment and CUB to propose a $27.01 million adjustment. PGE argues that these recommendations are misguided for two primary reasons. First, PGE maintains that the success of a FERC complaint is uncertain at best, and the proposed adjustment should be discounted to reflect this uncertainty. Second, PGE states that there is no reason to believe that FERC will reform the contracts to current market prices. PGE believes that, if FERC acts at all, it is more likely to reform the contracts to what it concludes were just and reasonable prices at the time the parties entered into the agreements. PGE notes that if the reformed price was set at the June 19, 2001 price cap of some $91 per MWh, the refund to PGE and its customers would be zero based on the $85 per MWh average price of the disputed contracts.

Commission Resolution

The question whether PGE should challenge the disputed contracts at FERC is a difficult one. In defense of its decision not to do so, PGE cites the potential long-term harm to the customers and the speculative and small potential benefits. The potential harms that PGE alleges, however, are just as speculative as ICNU's and CUB's predictions of success at FERC. As ICNU points out, there is no evidence that any of the utilities that have filed complaints at FERC have been subject to increased costs or discrimination among trading partners. Moreover, PGE fails to persuasively explain how its decision to challenge the four contracts would detrimentally impact investment in new generation facilities when several other Western utilities are currently challenging hundreds of power contracts at FERC.

PGE also cites conflicts with FERC's Pacific Northwest refund proceeding. While PGE claims that the company and its customers benefited from a number of advantageous power sales in early 2001, PGE fails to quantify that benefit to allow a determination whether the refunds for the disputed contracts could prove more advantageous to customers than the revenue for PGE's 2001 power sales. Moreover, PGE's reference to the federal ALJ's conclusions in that docket fails to note that the ALJ made those proposed findings in September 2001, prior to Enron admitting to certain questionable trading practices. Since that time, FERC has opened an investigation into Enron and PGE, and several parties have asked FERC to reopen the record in the Pacific Northwest refund proceeding. In light of these revelations, this Commission has joined other entities and urged FERC to aggressively investigate whether any market manipulations occurred.

PGE also failed to address ICNU's and CUB's inquiry about the company renegotiating the disputed contracts. While PGE's eager promotion of the potential problems of filing a FERC complaint has possibly now undermined its ability to settle any such claims on favorable terms, we are troubled by the failure of the company to provide any evidence that it seriously examined the possibility of settlement or renegotiation of the contracts.

Unfortunately, the failure of PGE to pursue reformation or renegotiation of the contracts is also subject to additional scrutiny due to Enron's ownership of the company. Although PGE denies that Enron influenced PGE's decisions in this regard, an undeniable potential conflict of interest exists given that an Enron subsidiary is a defendant in FERC complaints. Under the circumstances, it is even more imperative for PGE to establish that its management of these contracts focuses solely on what is in the best interest of PGE and its customers.

Despite our concerns about PGE's management of the contracts, we agree with the company that ICNU's and CUB's proposed remedies fail to reflect the uncertainty of success in reforming or renegotiating the contract. Whether FERC will begin to reform contracts at prices lower than those contained in the disputed contracts remains in doubt.

In addition, the intervenors proposed remedy has, in large part, been rendered moot by our conclusion that PGE was, in part, imprudent in entering the disputed contracts. Absent that prior conclusion, we might be inclined to impose some disallowance based on ICNU's and CUB's concerns about PGE's management of these contracts. However, given the significant disallowance we have imposed, and in light of the uncertainties surrounding PGE's success in reforming or renegotiating the contracts, we decline to impose an additional disallowance here.

It is important to note, however, that PGE is not foreclosed from filing a complaint and may yet pursue relief from FERC. Under current FERC guidelines, PGE has until November 1, 2002 to seek a refund for the entire 2003 period. It may also file a complaint after that date for a shorter refund period. It is unknown whether circumstances may arise that would make a complaint more favorable to PGE. Perhaps our decision to disallow a significant portion of these contracts might now motivate PGE to seek FERC relief. To fully protect PGE's ratepayers, the Commission reserves the right to examine the prudence of PGE's management of these contracts for the remainder of their term and to possibly disallow additional costs.

C. Mirant Contract

ICNU observes that PGE's contract with Mirant requires each party to maintain certain credit levels, and that Moody's downgraded Mirant below that required level in December 2001. In response to the downgrade, PGE requested a performance assurance from Mirant, but Mirant refused. ICNU claims that Mirant's refusal constitutes a default under the agreement that allows PGE to terminate the agreement. PGE, however, did not take further action because Mirant concluded that it could, in turn, require PGE to extend its collateral in an amount that would exceed PGE's requested performance.

ICNU faults PGE for failing to further pursue this matter. ICNU notes that there is no evidence that PGE took any action to verify Mirant's claims or calculations. Such inaction is troubling, ICNU continues, in light of the fact that Mirant is currently under investigation by the Securities and Exchange Commission (SEC) and that the SEC recently found that Mirant's accounting certification was not in compliance. Under these circumstances, ICNU believes that PGE should be taking aggressive steps to attempt to escape from, and preserve its rights with respect to, this unfavorable contract.

PGE responds that the Mirant downgrade does not permit PGE to terminate the contract, but rather only ask for a performance assurance, which the company did. Moreover, even if it could terminate the agreement, PGE states that it could not reduce its power costs by doing so. PGE notes that calculation of a termination payment is based on the then-current market price. Thus, if the current market price is below the contract price, PGE explains that PGE would owe Mirant a termination payment equal to the difference between what PGE would pay under the terminated transaction and what the company would pay at current prices for replacement power. Termination, PGE concludes, would not reduce the company's power costs.

Commission Resolution

We find that PGE has reasonably investigated the Mirant downgrade and concluded that the downgrade provides no means of escape. As PGE notes, the downgrade did not permit PGE to terminate the contract, but rather to request a performance assurance. PGE did make such a request on December 21, 2001, when it requested Mirant to provide a performance assurance of $15 million. Mirant responded by noting that, on a mark-to-market basis, Mirant was exposed to PGE in an amount well above $15 million and, under the terms of the contract, could demand a performance assurance or guaranty in an amount greater that $15 million. This response was acceptable to PGE, which is all that the contract required.

Moreover, even if the credit downgrade enabled PGE to terminate the contract, we are convinced that PGE would not be able to reduce its net variable power costs by doing so. The practical effect of the termination provisions in the contract does not allow PGE to avoid the costs that the Mirant agreement obligated the company to pay.

III. Monet

A. Monet Design

ICNU claims that the Monet model should be reformed or replaced because it (1) lacks documentation; (2) is poorly designed; and (3) has not been verified. It also contends that the hourly model makes it difficult to verify the calculations performed in the model. It notes that PGE has not "benchmarked" the results of the model against actual historical data or other models in the last five years, even though the company has made a fundamental change in the model's dispatch methodology since that time. To ensure an accurate forecast of PGE's power costs in the future, ICNU contends that the Commission should order PGE to reform or replace Monet.

PGE disputes ICNU's criticisms of Monet. PGE contends that, contrary to ICNU's allegation, Monet is not a "black box" because all of its input can be readily viewed in Excel spreadsheets. Moreover, PGE highlights the fact that the company has disclosed Monet's source codes to all parties. PGE notes that ICNU's expert witness testified in another proceeding that the ability to review the source code was an important reason favoring the use of a utility's customized model over vendor-supplied models.

PGE also claims that Monet's design is superior to vendor-supplied models because of its better ability to model Northwest power markets. PGE explains that it has used various vendor-supplied models in the past—including the one mentioned by ICNU—but found them deficient in modeling the Western power market.

Finally, PGE does not understand the basis for ICNU's claim that Monet lacks verification. Again, PGE believes that Monet is more transparent than vendor-supplied models because PGE has disclosed its source code. PGE also states that it has benchmarked Monet against Proscreen, a vendor model, and actual power costs.

Commission Resolution

We are not persuaded that PGE should replace or reform Monet at this time. PGE has used Monet to forecast power costs since the mid-1990s. During that period, the parties and the Commission have had many opportunities to investigate how the model operates and to verify its accuracy. While no model is perfect, Monet compares favorably to vendor-supplied models for several reasons. First, PGE has revealed the model's source code, enabling the parties to examine Monet's underlying logic and investigate appropriate changes. Second, unlike commercial models, Monet has no licensing constraints that may restrict the ability of third parties to assess and use the model. Monet is also better suited to model the Northwest power markets.

Furthermore, Monet appears to do a good job at forecasting power costs. Monet's calculations are easy to understand and fundamentally sound. Moreover, PGE has expressly stated that it is always seeking to improve Monet and would welcome any suggestions concerning future improvement. On this record, we find no basis to reject the model's use to forecast PGE's power costs in the future.

B. Hydro Modeling

ICNU and CUB object to PGE's adjustment to the Pacific Northwest Coordination Agreement (PNCA) headwaters benefit study. PGE has traditionally run the PNCA model in standard mode, which starts each simulated water year with full reservoirs. In this docket, PGE initially ran the PNCA study in continuous mode, which starts each year with reservoir levels from the end of the prior year. This change increases PGE's variable power cost forecast by approximately $3 million.

ICNU acknowledges that the adjustment is designed to account for the fact that the system could start some year in the future with less than full reservoirs. However, because reservoir levels are expected to be full in 2003, ICNU contends that there is no need for an adjustment to account for the possibility that this next year will begin with less than a full levels.

ICNU and CUB also argue that the adjustment is not appropriate given the parties' power cost stipulation in docket UE 115. By adopting that stipulation, the Commission allowed the company to make an $11.3 million adjustment to compensate for the poor hydro conditions that existed at that time. The intervenors contend that it would be unfair and bad regulatory policy to provide an additional adjustment for hypothetical hydro deficits on top of an explicit adjustment for actual hydro deficits.

In its rebuttal testimony, PGE acknowledges that the parties had less time to review this adjustment and that the company received a "poor" hydro adjustment in docket UE 115. For these reasons, it agrees to delay the proposed enhancement until next year.[25] To accomplish this, PGE filed what it terms a "simple" Monet update that removes the hydro-related and other adjustments. Specifically, the "simple" update removes updates and enhancements that were related to: (1) hydro; (2) thermal plant heat rate or capacity; and (3) maintenance for the Bull Run and Beaver plants.

Staff does not support the use of the "simple" Monet update. While Staff endorses the removal of steps related to the changes to the PNCA study, it objects to the removal of some 23 other adjustments not related to PGE's modifications with the Headwaters Benefit Study that PGE included in its "simple" Monet filing.

Commission Resolution

We agree with the parties that PGE's hydro modeling adjustment should be removed for 2003. First, as a procedural matter, the parties had only a month to evaluate this adjustment. CUB also notes that PGE was unable to fully explain the hydro forecast at the workshop scheduled to address hydro issues. Second, as a substantive matter, the company received a favorable adjustment in docket UE 115 for poor hydro conditions. Under these circumstances, we agree that the three steps listed in PGE's filing related to this hydro adjustment, Steps 141, 142, and 143, should be removed to allow further review.

We do not, however, support the removal of the other 23 steps that were part of the "simple" Monet update. As Staff notes, these steps are unrelated to the proposed changes to the PNCA hydro study. They include adjustments related to thermal plant heat rate or capacity, plant maintenance, heat recovery steam generators upgrades, and other enhancements or corrections. While PGE explains that it removed these additional steps in response to the intervenor's concerns about the scope of this docket, the company fails to explain why it was appropriate to remove these adjustments and not others. As stated above, PGE proposed over 163 adjustments in this docket. Moreover, as Staff notes, some of these adjustments selected for removal are corrections. For example, Step 24 corrects the modeling of holidays in Monet as off-peak. Step 144 updates the efficiency factors for two of PGE's hydro plants that had turbine-runner improvements in 2001. Because the costs of those improvements were reflected in rates

[25] We note that, given the size of the UE 115 adjustment, CUB argues that PGE should not implement this change until 2005. *See* CUB Opening Brief at 11.

approved in docket UE 115, removing Step 144 in this docket would cause a mismatch of costs and benefits going forward.

We acknowledge PGE's efforts to minimize the number of adjustments in this RVM proceeding to address concerns raised by the intervenors. PGE has failed, however, to provide any explanation as to why these additional 23 steps should be removed. While we agree that Steps 141, 142, and 143 relating to the PNCA hydro study should be excluded, we find no basis to exclude the other 23 steps unrelated to that issue. PGE should modify its forecast accordingly. This modification reduces PGE's power cost forecast by approximately $8.5 million.

C. Unplanned Outages at Beaver and Coyote

ICNU objects to PGE's use of older data to model unplanned outages for the Beaver and Coyote power plants. ICNU explains that unplanned outages can occur at any time and can have a major impact on power costs. ICNU adds that PGE uses the so-called "derate" method to simulate these outages. Under this approach, if PGE has a 100 MW plant with a 20 percent unplanned outage rate, the company would treat the generating facility as an 80 MW plant available all the time.

ICNU notes that PGE generally computes unplanned outage rates based on the most recent four years of historical data, *i.e.*, 1998 to 2001. However, PGE makes an exception to this rule for modeling its Beaver and Coyote plants. Instead of using the most recent data, PGE uses data from 1996 to 1999. ICNU alleges that the use of this outdated information significantly increases the outage rates for both plants and inflates PGE's net variable power cost estimate by some $524,000.

In response, PGE acknowledges that utilities generally compute unplanned outages based on the most recent four-year period. PGE claims that its substitution of older data is justified because the 1996-1999 period is more representative of the outage rates that Beaver and Coyote will experience during 2003. PGE explains that, due to the high power prices, both Beaver and Coyote ran more continuously during the last two years. PGE expects that Beaver and Coyote will run at more normal levels in 2003 and, consequently, be brought on and off-line more frequently. This increased cycling, PGE argues, will cause more problems with the plants and, consequently, higher outage rates.

<u>Commission Resolution</u>

We acknowledge the reported relationship between cycling and component fatigue, which may cause an unplanned outage. Nonetheless, industry analysts that perform production cost models have apparently never considered the relationship significant enough to modify input data. Indeed, a regression study performed by ICNU found no statistical relationship between how continuously the Beaver and Coyote plants are run and the outage rates for those plants. Thus, there is no empirical basis for PGE's proposed adjustment.

Furthermore, PGE's inclusion of data from 1996 and 1997 fails to acknowledge the fact that market prices were considerably lower in those years than the prices Monet forecasts for 2003. For these reasons, we conclude that PGE has failed to justify a deviation from standard industry practice in favor of using older data. The use of data from 1998-2001 decreases PGE's power cost forecast by approximately $0.5 million.

D. Planned Outages at Colstrip

ICNU disapproves of PGE's calculations in modeling planned outages for the Colstrip plant. ICNU notes that the North American Electric Reliability Council (NERC) has promulgated a standard equation to estimate the forced outage rate of a particular plant.[26] In estimating the forced outage rate for Colstrip, however, PGE modified NERC's standard equation by substituting the plant's capacity factor (CF) for its equivalent availability factor (EAF).[27] ICNU contends that PGE's deviation from standard industry practice is unjustified and arbitrarily inflates PGE's net variable power cost estimate by $1.5 million.

PGE explains it made the adjustment because it obtains less energy from Colstrip than one should expect from the plant's EAF. PGE highlights that it has normally received 1 to 4 percent less generation—based on the plant's CF—than would be expected—given the plant's EAF. To account for this, PGE assigns the "missing generation" to unplanned outages. PGE has not identified any specific reason why the generation at Colstrip has fallen short of potential levels, but speculates that up or down ramping periods, generation variances including minor forced derations, or transmission pathway deratings may be responsible.

PGE further contends that its substitution of CF for EAF makes sense for a plant like Colstrip, which had no economic shutdowns or turndowns during 1998-2001. PGE explains that Colstrip is a mine-mouth coal plant with a low-cost fuel supply. As such, Colstrip has an unusually low dispatch, or marginal cost. For that reason, Colstrip has essentially been run continuously during these past few years during the Western power crisis. In the absence of any outages or turn-downs, PGE believes that the EAF should, in principle, be the same as the CF. PGE concludes "[i]f we ask the plant for the maximum it can deliver at all times, what we get (the CF) should be considered the equivalent annual availability for power cost forecast purposes.[28]

<u>Commission Resolution</u>

While it appears that an aberration exists in PGE's system that prevents the company from obtaining expected generation levels from the Colstrip plant, we are not convinced that creating "phantom outages" is the appropriate solution. First, PGE's

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[26] A forced outage includes any condition that requires the plant to be removed from service.
[27] A plant's CF is a measure of how much energy a plant actually delivers over a specified period of time. The EAF is a measure of how much energy is potentially available from the plant.
[28] PGE/300, Niman-Hager/15, lines 3-5.

proposed adjustment violates standard industry practice and is contrary to the company's own forecasting methods that it uses for other plants. Second, PGE's adjustment fails to account for the fact that a plant's CF, by definition, will never exceed its EAF, even those that run continuously.

We are also troubled by PGE's decision to make this adjustment despite the fact that it is unable to identify the source of the generation shortfall or to quantify its effect. If the loss of energy from Colstrip is due to minor forced derations as PGE speculates, the company should be able to modify Monet to capture these derations.

For these reasons, we disagree with PGE's adjustment to a standard industry equation used to compute forced outage rates when outages have nothing to do with the alleged problem. As ICNU explains, customers should not be required to pay increased power costs simply because PGE cannot identify an aberration in its system. The adjustment should be removed from PGE's forecast, which reduces variable power costs by $1.5 million.

IV. Non-Variable Power Costs

A. Production O&M Costs

CUB contends that PGE's actual production costs at several plants declined by $3.3 million between the past two twelve-month periods—July 2000 to June 2001 and July 2001 to June 2002. CUB claims that this is evidence that production O&M costs are declining, and that these reductions should be incorporated into customer rates for 2003.

PGE acknowledges that the company has reduced production O&M costs but disagrees that the reductions should be used to reduce rates in UE 139. PGE claims that the company's current forecasts for 2002 production O&M are higher than the level allowed in the test year for UE 115. It explains that there are two ways to forecast 2002 production O&M costs. Under the first method, actual costs through July are added to the remaining budget for August through December. The second method uses PGE's current revised forecast, which utilizes actual expenditures through June and adjusts for any timing differences. Either approach, PGE contends, yields a higher 2002 production O&M than that in the UE 115 test year.

Commission Resolution

There is no dispute that PGE has reduced its production O&M costs from 2000 and 2001 to 2002. In order to use the reductions to reduce retail rates for 2003 via the RVM, however, we must compare these actual expenditures to the levels authorized in UE 115. CUB provides no such information that would allow us to make that comparison. PGE offers two forecasts to show that 2002 expenses will actually exceed the UE 115 authorized level. Accordingly, on this record, we find no basis to reduce PGE's 2003 base rates based on the company's production O&M costs.

B. Production Rate Base

CUB contends that PGE depreciated more production plant than it added in 2002, and that its net utility plant associated with generation has declined by $9.7 million since UE 115. Incorporating this reduction results in a revenue requirement reduction of $1.2 million.[29]

PGE objects to CUB's adjustment on the grounds that it is based on an estimate from the company's transition model. PGE explains that, given the time constraints in the proceeding, it was not able to produce a definitive study of forecasted 2002 production rate base.

Commission Resolution

We agree with CUB that PGE's revenue requirement should be reduced by $1.2 million. While PGE argues that it did not have time to prepare a definitive study on its forecasted 2002 production rate base, the company does not refute the accuracy of the estimate provided to CUB.

C. Trading Margins

CUB notes that, after UE 115, PGE added an additional $2 million of trading margin to its budget, split equally between speculative and retail trading. CUB contends that the $1 million for retail trading should be included in this docket.

PGE responds that CUB's $1 million adjustment for increases in trading margins is unjustified. PGE explains that the increase in trading margin was a "stretch" goal.

Commission Resolution

We reject CUB's proposed adjustment. We agree with PGE that the company's increase in trading margins is not a reliable forecast for 2003. There is no evidence that the company is likely to achieve that goal, especially under current market conditions.

[29] CUB also initially proposed another $2 million reduction based on an assertion the PGE had cut $15.4 million from its 2002 budget for production capital expenditure. CUB withdrew that request after PGE showed in its rebuttal testimony that it did not cut or delay capital expenditures on the production side. CUB Opening Brief at 9.

V. Resource Stacking

CUB explains that, for the purpose of establishing a one-time valuation of the company's generating resources for direct access customers, the generation resources allocated to large non-residential customers were fixed based on the 12-month period ending September 30, 2001. In the UE 115 power cost stipulation, however, all long-term resources were allocated on that basis to all customer classes. CUB believes that the resource stacking approach in UE 115 made sense at the time, because the loads on that date were a good representation of the share of loads for the UE 115 test year. CUB is concerned, however, that the approach will cause problems over time as the relative share of resources among customer classes continues to change.

For this reason, CUB contends that the Commission should address this issue now before the problem gets worse and requires a significant shift in rates between customer classes to solve. CUB argues that it makes little sense to fix the share of long-term resources between residential and small commercial customers based on the 12-months ending September 30, 2001. CUB asks the Commission to fix only the large non-residential customer share and then allocate the remainder of long-term resources based on expected loads in the UE 139 docket.

PGE questions CUB's proposal and notes that the appropriate basis for allocation of long-term resources is being addressed in dockets AR 441/417. ICNU objects to CUB's proposal, noting that CUB agreed to the current allocation as part of the power cost settlement in docket UE 115.

Commission Resolution

ICNU is correct that CUB and the other parties agreed to the allocation of generating resources as part of a resolution of numerous power cost issues in docket UE 115. Because the Commission approved that stipulation, the alteration of the resource allocation would require an amendment of Order No. 01-777. We conclude that the record does not contain sufficient evidence to support such an amendment to adopt CUB's proposal.

ORDER

IT IS ORDERED that:

1. The Resource Valuation Mechanism, as filed by Portland General Electric Company and as modified by this order, is adopted.

2. On November 6, 2002, Portland General Electric Company shall update the data inputs to the Monet model and incorporate the changes the Commission requires in this order.

3. Portland General Electric shall make the final Monet run, with updated forward curves for gas and electricity, on November 14, producing the Resource Valuation Mechanism adjustment for 2003 on November 15, 2002.

Made, entered, and effective OCT 30 2002.

Lee Beyer
Commissioner

Joan H. Smith
Commissioner

Commissioner Beyer, concurring:

Oregon law clearly places the responsibility for proving that requested rates are just and reasonable upon the requesting utility. It is not the responsibility of the Commission to search for justification of prudence. The Commission's responsibility is to look at the record and see whether the evidence provided demonstrates that the utility's actions were prudent and the resulting rates just and reasonable.

In reviewing prudence, the Commission places the bar high for its actions; it does not lightly second-guess a utility. The Commission's judgments, however, must be based on the record. This order clearly lays out the facts of the case. It notes that the actions covered were taken in an exceptional period with much uncertainty. It is possible that PGE's actions were indeed prudent. The evidence provided, however, does not allow the Commission to reach that decision. The four power purchase contracts as noted in this order were made outside of PGE's routine practices and outside of policies they enunciated in this and prior dockets. The market, while perhaps "nuts" as the company stated, was evolving quickly as noted in the NPPC analysis, which PGE referenced. The company, however, did not provide persuasive evidence why going long in this market, in spite of past practice and policy, was justified.

Lee Beyer
Commissioner

Chairman Hemmingway, dissenting in part and concurring in part.

The period from June 2000 to June 2001, was one of unique peril for the electricity industry and its customers in the western states. Wholesale prices on the spot market soared to unprecedented levels, unimagined before this time. Spot prices during that year soared to well over $1,000 per megawatt hour on frequent occasions and often stayed above $300 (30 cents per kilowatt-hour) for weeks at a time. These prices were at least ten times what had been experienced in the past.

The Pacific Northwest was not immune from these events. While the summer of 2000 allowed Northwest utilities to sell into the California market at high prices, the winter of 2000-2001 saw prices spike again, despite an overall reduction in loads in most of the western interconnection, which is for the most part summer peaking. The drought, and consequent low stream flows, meant that Northwest utilities were for the most part buyers in this winter market. PGE, in the position of having to purchase about half the power it sells, was especially challenged by this unexpected conflation of events.

The authority of a utility regulator to look backwards and judge the prudence of an action taken by a utility in the past is one of the most substantial powers available to the regulator. The utility has no opportunity to undo the action reviewed for prudence. The company has already incurred the costs of the action under review. A finding of imprudence leaves the utility with no choice but to charge costs to shareholders.

With the benefit of hindsight, it is easy for a regulator to judge whether an action by a utility, in this case a number of PGE power purchases, was a mistake or not. In the case of the four contracts under dispute in this case, it is clear that PGE would have done much better by waiting. Now it is clear that the market adjusted to new hydro conditions and new generation coming on line.

However, the question before the Commission is not whether the purchases were mistakes, but whether PGE acted prudently at the time it made the purchases, given the state of the power markets at that time.

The Commission must be extremely careful in exercising its power of prudence review. It is easy to see in hindsight that the high prices in the western market during that period were temporary and just as easy to see that pricing returned to near "normal" levels in June 2001. However, the question is how would a prudent power purchaser have acted during that time in buying power for future delivery. The Commission must be careful not to simply substitute its business judgment in prudence reviews. The company must be allowed to exercise business judgment which at times will lead to mistakes, such as the 2003 forward contracts turned out to be. The Commission should not demand perfection from the companies it regulates. It simply should require exercise of prudent business judgment, which on occasion will turn out to be mistaken.

I cannot agree with the majority that the record in this case supports ruling that the four contracts at issue were incurred imprudently by PGE. The events of 2000-2001 were beyond any experience of anyone in the electricity industry. The markets were behaving in unprecedented and unpredictable ways. No one had any idea whether the market prices being experienced at that time represented a long-term trend or would be short-lived.

The majority opinion, with respect to the four contracts at issue, relies on three theories to find these contracts were imprudently executed by PGE. First, the majority argues that PGE violated its own purchasing principles by buying more than 18 months in advance. Second, PGE bought in an "illiquid" market. Third, the NPPC report of October 2000 indicated that the power situation should be improving.

Each of those rationales fails to justify a finding of imprudence. First, PGE's practice of buying only 18 months in advance was not a "rule" but simply a practice PGE generally followed in stable markets.[30] In fact, PGE had signed power purchase contracts for up to 3 1/2 years in advance of need as recently as May 2000, without any objection from Staff or intervenors.[31] What makes the four contracts at issue troublesome to the parties is not that they were signed so far in advance of need, but that the price is higher than anyone would really like to pay.

When is it appropriate for PGE to buy beyond the 18 month time horizon? Certainly, one time would be when there are good prices in the marketplace. That situation is not the one at issue here. The other time it would make sense to buy beyond the 18 month horizon is when markets are unstable and unpredictable. Almost no one

[30] *See* PGE 400/Pollock/Lyman at 6.
[31] *Id.*, at 8.

predicted that the events of the winter of 2000-2001 would occur in the power markets. No one knew whether the western states were experiencing a temporary, unique phenomenon of high prices or whether a new long-term market trend was being signaled. The fact that early 2001 prices throughout 2002 were high, certainly suggested that the market was not responding to expectations about returning to more normal hydro conditions or new resources coming on line.

I do not believe that it is important that only a few trades were made for 2003 at the time PGE signed the contracts at issue. What trades were made did suggest that prices would remain high, and prices for all of 2002 were high, as well. If PGE had bought 50 percent of its purchased power needs for 2003 in such an "illiquid" market, then I would agree with the majority that PGE had acted imprudently. However, I believe it was an exercise in reasonable prudence for PGE to hedge its concerns about where the market would go for 2003 by purchasing 15 percent of its 2003 needs early in 2001. If prices had gone even higher in 2003 than the four purchased power contracts, would the majority now be finding PGE imprudent for not having bought more of its needs for 2003 in 2001?

Much is made in the testimony and briefs about the NPPC report of October 2000 that predicted an improvement of the western power supply situation by 2003. However, the NPPC report makes no mention of power price, only supply. While it might have been axiomatic in October 2000, that prices will go down as supply goes up, particularly in the long-term market, by December those assumptions were no longer valid. Despite expectations of power flowing from California to the Northwest in the winter, a return to normal hydro conditions, and new plants coming on line, long-term prices into 2002 and 2003 did not show any moderation.

Whether it was market manipulation, California's entry into the long-term market, or other factors, the western power market in the first half of 2001 was behaving in ways it had never behaved before. The Commission should have found PGE imprudent if it had not taken some hedging action at that time to protect its customers in 2003, rather than find PGE imprudent for hedging against disaster in a very uncertain and unprecedented situation.

It is a real stretch to suggest, as the majority does, that prudent persons would have made different decisions in the first half of 2001, had they been in the position of purchasing power for PGE. I believe that PGE should be allowed to recover the full amount of the four contracts at issue.

I also dissent from the majority's treatment of the "simple" Monet adjustment proposed by PGE. While PGE offered not to make the Monet adjustments related to hydro modeling, the expectation of costs in the record is $3.9 million for that proposal. I do not believe that there is a record to sustain an $8 million adjustment to the Monet model.

In all other respects, I agree with the majority position.

Roy Hemmingway
Roy Hemmingway
Chairman

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.