BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 165 & UM 1187

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In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC,	)
	)
Application for a Hydro Generation Power	)
Cost Adjustment Mechanism, &	)
Application for Deferral of Costs and	)
Benefits Due to Hydro Generation Variance.	)
	)

SURREBUTTAL TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 2, 2005

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Our names are Bob Jenks and Lowrey Brown, and our qualifications are listed in our opening testimony in UE 165, Exhibits 101 and 102 respectively.

I. Introduction

CUB recommends that the Commission reject outright the power cost adjustment mechanism proposed by PGE and Staff for UE 165 & UM 1187. The mechanism is fatally flawed. It would likely overcharge customers for the cost of replacing PGE's lost hydro. It fails to recognize the efforts to involve customers through calls for conservation, even though customers have been told that this will reduce, "future rate increases." It fails to recognize the prudent actions a utility should take to deal with low hydro conditions, and instead would charge customers as if the utility were acting imprudently. It is based on a model that has not yet been developed, so there is no way to test the mechanism. It contains an unreasonably small deadband, and, finally, it is improperly applied retroactively.

For the deferral, UM 1187, CUB recommends that the Commission consider a power cost deferral with a deadband and sharing bands similar to those adopted in UM 1008 and UM 1009.

For the power cost adjustment mechanism, UE 165, CUB recommends that the Commission not adopt any mechanism. The power cost adjustment effectively only applies prospectively to one year, 2006, when a new power cost adjustment will be developed in a PGE general rate case. A one-year power cost adjustment is not good policy, and there is no reason the Commission shouldn't wait to consider the ongoing mechanism proposed in the Company's rate case. If the Commission feels compelled to adopt a power cost adjustment mechanism for 2006, it should base the mechanism on CUB's proposed deferral mechanism in UM 1187, with deadband and sharing bands adjusted to recognize the asymmetry of the financial impacts of high and low hydro conditions.

Finally, the Commission should initiate a proceeding to investigate the least-cost, least-risk approach to hydro variability. Rather than this continual focus on who pays the costs associated with hydro variability, we ought to spend some effort focusing on how to prudently and properly manage this risk.

II. PGE's Proposed Mechanism

PGE's proposed mechanism is designed for only two years, 2005 and 2006. The Company plans to file a general rate case in that time, and both Staff and the Company anticipate an ongoing power cost adjustment mechanism, effective in 2007, as part of that rate case. The Company and Staff recommend that the proposed mechanism be retroactive to January 1, 2005. It should be noted that, though our discussion refers to a single proposed mechanism, it is being applied to two different dockets: UM 1187, an application for a hydro deferral, and UE 165, an application for a hydro power cost adjustment mechanism. Our comments, therefore, refer to a single power cost adjustment mechanism which the Company and Staff propose to make retroactive.

A. How It Works In A Nutshell

To briefly summarize PGE's proposed mechanism, it is important to understand that the rationale behind power cost adjustment mechanisms is to compensate the utility or the customers for significant variations between <u>actual</u> power costs and the power costs that were <u>forecast</u> in rates. Typically the power costs that were forecast in rates serve as the baseline, and are compared to actual power costs incurred by the utility. The difference is then subject to whatever deadband and sharing mechanisms the Commission finds to be reasonable.

In the PGE & Staff proposal the baseline power costs are measured using the Company's annual Resource Valuation Mechanism (RVM). The baseline, therefore, is the final RVM MONET run, updated for the results of the direct access window. For actual power costs, the costs to be compared to this baseline, the proposed mechanism uses a second, back-cast MONET run that is updated for 1) the Company's actual hydro generation, 2) actual market electricity prices, and 3) actual market gas prices. It is not updated for forward power purchases or actual loads, but instead relies on the forward purchases and expected load that was used in the original MONET run.

The proposed deadband is from $7.5 million when actual power costs are lower than were forecast (credit to customers), to $15 million when actual power costs are greater than were forecast (cost to customers). Costs or credits beyond the deadband are shared 80% customers and 20% Company.

B. Anomalies Of The Proposed Mechanism

There are a number of oddities with the Company's proposed mechanism, most notably its use of modeled costs to approximate known actual costs, its approach of updating some variables with actual data, but not others, and its use of a small deadband. In our opening testimony, we indicated a preference for a hydro-variability power cost adjustment mechanism, and the proposed mechanism is intended to do that. Unfortunately, limiting the variables to be updated as a method of limiting the scope of the mechanism does not yield rational results. We will address this distinction in our final recommendations, and focus on the proposed mechanism, such as it is, in the body of our testimony.

i. Mechanism Uses Modeled Costs Not Actual Costs

It seems fundamentally odd to us to design a power cost adjustment mechanism to track the difference between forecast costs and actual costs, but then not use actual costs when calculating that difference. MONET is PGE's computer model that forecasts power costs for ratemaking purposes. Even though MONET will be updated with actual data for the back-cast run, it will nevertheless yield computer-modeled power costs, not actual ones.

ii. Mechanism Updates Some Variables But Not Others

This is further complicated by the Company and Staff's proposal to update some variables in MONET for the back-cast run, but not others. PGE's actual hydro generation will be used in the back-cast run, but the actual load on its system will not be. Actual electricity and gas market prices will be used, but actual contracts signed after the final RVM run will not be included in the back-cast run. This strange chimera uses tools for forecasted ratemaking to approximate actual expenses that have already occurred, and in the process ignores the actual data from some key variables while including the actual data from others.

iii. Mechanism Has A Narrow Deadband

The proposed mechanism has a deadband that is significantly smaller than the ones that have been used in recent history in Oregon. In 2001 and 2002, the Commission approved a Power Cost Adjustment and a Power Cost Deferral with deadbands of $35 million and $28 million respectively. In opening testimony, Staff proposed a deadband of $40 million. The tiny deadband in this proposal is not justified in light of these precedents.

III. Power Cost Adjustment Doesn't Use Actual Power Costs

There are a number of problems which stem from the proposed mechanism's use of computer-modeled costs to approximate known, actual power costs. The mechanism uses a forward-looking projection and then a back-cast approximation to measure a cost difference, but actual costs never enter the discussion. To our and the Company's knowledge, there has never been a comparable power cost adjustment that does not calculate the difference between baseline, forecasted costs and actual power costs.

A. Uncharted Waters

Exhibit 201 is PGE's response to CUB's data request 30 asking the Company if it was aware of any cases where the Commission allowed deferral of an amount calculated as the difference between an original, theoretically-modeled cost, and another theoretically modeled cost. The two examples provided by the Company were an IT-related deferral for 2000-2002, UM 1131, and a deferral relating to energy efficiency activity in 1991, OPUC Order 91-98.

i. UM 1131 Deferral Of IT Costs

The deferral in UM 1131 used, for a baseline, the expected Information Technology (IT) capital costs set in UE 115, and compared this to the actual IT capital costs that were incurred by the Company. In its response to our data request, the Company points out that the deferral did not update PGE's capital structure or its cost of capital when calculating the Company's rate of return to be used on this capital investment.

IT investments are considered capital expenditures, and are included in a utility's ratebase, upon which the utility earns its rate of return. Deferrals, on the other hand, are often for non-capital costs that would not be included in a utility's ratebase, but deferred accounts currently accrue interest at the utility's authorized rate of return set in its most recent rate case[1]. Thus, at any given point in time, whether amortizing a deferred account or a capital expenditure, the calculation would be the same.

In this case, the Company is arguing that because the deferred account accrued interest at a rate of return set earlier, rather than the current rate of return that would have

[1] Though the Commission is considering whether this is the appropriate interest rate to use in UM 1147.

been used had the Company filed a rate case for its IT capital costs, that UM 1131 represents a departure from using actual costs in a deferral. This is absurd. Currently, all deferred accounts accrue interest at the Company's rate of return; no distinction is made as to whether the cost was a capital cost or not. The UM 1131 deferral was calculated by taking the difference between the <u>forecasted</u> IT costs and <u>actual</u> IT costs. This is the way we have always done both deferrals and power cost adjustments.

ii. UE 79 Deferral Of Energy Efficiency Related Costs

The deferral approved in OPUC Order 91-98, like the deferral in UM 1131, used actual expenditures, and accrued interest at the Company's rate of return set in UE 79. The deferral amount was the difference between the baseline projected program expenditures and the actual program expenditures, not an estimate of program expenditures. What the deferral did model, however, was the energy savings reaped from the efficiency programs to account for the effect of the energy efficiency programs on load. To our knowledge, there is no way to accurately measure energy saved from efficiency programs, and so there is no choice but to use a modeled number. For those costs that could be based on actual numbers – the program expenditures – the mechanism used actual costs. Only when an actual number was not available, did the mechanism turn to a modeled approximation.

These two examples, provided by the Company, are not power cost adjustments, but more importantly, they show that actual costs were used when they were available, and that the precedent these mechanisms set for using modeled costs to approximate known, actual costs – under any circumstance – is tenuous at best.

B. Load

As mentioned above, PGE's proposed mechanism does not update the back-cast MONET run with actual customer usage. This means that the back-cast MONET run with its updated hydro generation and market prices, will dispatch PGE's thermal assets and make market purchases as if the projected, normalized load had actually come to pass, which is not the case.

i. Winter Load Is Down

The warm dry conditions that produced this year's low hydro conditions are the same warm, dry conditions that reduced residential customer loads on PGE's winter-peaking system by 3.2% in January, 9.6% in February, 8.6% in March, and 4.2% in April. For all firm load, demand was down 0.3% in January, 3.6% in February, 3.5% in March, and 3.3% in April. Exhibit 202. The Company's mechanism, however, ignores this, and the back-cast MONET run used to approximate actual costs will calculate the Company's power costs as if a normal winter load had been on the system. When load is down, the Company will need to replace less hydro generation than if load had been as forecast. We are not claiming that the loss of load balances out the lost hydro generation, but it does mitigate some of the impact.

ii. Customers Charged For Electricity They Didn't Use

More importantly, in approximating actual costs using forecasted load, as opposed to actual load, the proposed mechanism would charge customers for a power cost difference on power they didn't use. The back-cast MONET run would replace 0¢/kWh variable cost hydro with Company-generated power or market purchases to serve a forecasted load that didn't materialize. This computer-generated number will then be compared to the baseline 2005 RVM run in order to determine the power cost difference that customers will be responsible for.

Under the proposed mechanism, if customers use less electricity than projected, they will be charged for a power cost difference on energy they didn't use, while if they use more electricity than projected, they won't be charged the power cost difference on power they actually used. The model will charge customers for increased power costs up to the load that was modeled in the RVM, whether they use it or not, and then the model will ignore the increased power cost differential on load beyond that. When we forecast rates, we know that conditions will be different and that the utility's revenues will not be exactly as forecast, but we set a rate in cents per kWh and customers are charged that rate for the power they use. We don't design rates to charge customers for energy they didn't use, and there is no doubt that the proposed mechanism will calculate a customer surcharge for power in January through March 2005 that was not used.

The Company and Staff may argue that this risk falls both ways. Exhibit 203. We don't know for sure whether loads will be greater or lower than projected this year or next year, but this mechanism is retroactive to January 2005, and we do know that loads are down for the first third of this year. When this proposed mechanism was filed with the Commission, the Company was certainly aware that loads had been down during the first three months of the year, and, currently, we know that loads in 2005 are likely to be lower than forecast. We also know that, for the first four months of this year, PGE and Staff's proposed mechanism will include costs to serve load that did not actually exist.

iii. Mechanism Should Update For Load

Traditionally, utilities take the risk and enjoy the reward of load variations between rate cases. Rates may have been set wrong, in fact, they're bound to be wrong, and so some years the utility will over-collect and some years it will under-collect. This is done with the expectation that these load variations will balance out over time. The Company's proposed mechanism takes this traditional dynamic and turns it on its head. The mechanism would charge customers a surcharge for their projected load whether they used it or not.

Load variation is a normal risk taken by utilities, and there is no reason a power cost adjustment mechanism such as this, should not use customers' actual load when measuring actual costs. It should be noted that PGE, due to its RVM, now only bears the risk of load variation between its annual RVM filings. In order to ensure that the risk of load variation is not shifted to customers, a lost-revenue recovery mechanism should not be, and, appropriately, is not included in the proposed mechanism. PGE/900/Lobdell-Niman-Tinker/20. For CUB's discussion of the risks associated with lost revenue recovery mechanisms, please see Exhibit 204, which is an excerpt from CUB's testimony in UE 137.

C. Proposed Mechanism Quashes Conservation Incentive

Though, on a theoretical level, this issue is a subset of "Load," on a practical level, its ramifications extend well beyond regulatory theory, and into politics and public perception both of energy efficiency and conservation, as well as of the utilities themselves. In our opening testimony, CUB raised the issue of conservation. When is it appropriate to ask customers to help out during a drought by cutting back their usage, and how to give customers, "the option of reducing their usage today to help avoid higher rates in the future." CUB/100/Jenks-Brown/25. Unfortunately this mechanism ignores conservation as a response to low hydro conditions.

Customer conservation, however, is a real issue that cannot be ignored. In March, CUB joined with other Northwest stakeholders in calling for conservation. In that call customers were told that, because of this year's low hydro conditions, reducing their electricity consumption this year will minimize the economic impacts of the drought. A press release in March, signed by CUB, PGE, and a number of other utilities and energy organizations[2] is titled:

> **Dry weather prompts calls for wise use of energy**
> ***Saving energy will reduce future rate increases***

The press release then opens with a first sentence of:

> The Bonneville Power Administration, regional utilities and public interest groups today asked Northwest residents to help combat the economic effects of a dry winter by efficiently using electricity this spring and summer.

Exhibit 205 – BPA Press Release PR 36 05.

This press release was followed by an advertisement campaign repeating the call for customer conservation. We have called for conservation, PGE has called for conservation, and Staff supports the call for conservation. Staff's succinct reply to CUB data request 5 asking if Staff supports the call for retail customers to conserve energy was, "Yes." Exhibit 206. Under this mechanism, however, the message to conserve now in order to mitigate the future rate impacts of the drought is misleading at best, because the amount deferred is calculated using projected loads, not the actual load that reflects

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[2] Signed by BPA, Clark Public Utilities, the Citizens' Utility Board, the Energy Trust of Oregon, the Northwest Energy Efficiency Alliance, the Northwest Power and Conservation Council, PacifiCorp, Portland General Electric, the Public Power Council, and Puget Sound Energy.

customers' conservation. So customers' conservation reduces power costs for the utility, but the proposed mechanism will calculate costs for customers' bills as if they hadn't conserved at all. The Company will keep the benefit. Once the public understands this, it will significantly damage the public perception of conservation as well as of efficiency, and may sully the utilities' public image too. It also has ramifications for a regulatory system that is under attack for allowing utilities to charge customers for phantom taxes. We should not publicly encourage conservation, and then charge customers for a phantom load they conserved rather than consumed.

Yes, customers' current electric bills will be less if they use less, but telling customers that current conservation will reduce future rate increases is negated by the proposed mechanism. Customers' conservation will not impact what they pay for this year's hydro deferral, because that amount is calculated as if they had not conserved at all.

One could argue that customer conservation reduces pressure on the system as a whole, thereby lowering market prices which are updated in this mechanism, thus lowering the amount deferred. While there may be a theoretical rationale behind this, the extent to which PGE customers would have to conserve in order to impact the market price is questionable. It's a bit like telling people that driving less this summer will reduce oil demand and push OPEC to lower prices. Maybe … but it's a dubious connection for an individual consumer to make, and it is not the message that has been given to the public.

The calls for consumers to conserve electricity this summer have suggested a more direct financial impact. The news release cited above was titled: "Dry weather prompts calls for wise use of energy – Saving energy will help reduce future rate increases," which is a far cry from suggesting that if consumers save enough energy, the market price of power in the Western United States will fall, the utilities will not have to pay as much for replacement power and, therefore, customers might save money.

D. Model Presumes Imprudent Utility Action

On April 5th the Commission held a public meeting addressing this year's drought hydro conditions. The utilities spoke about their current position and their strategy for coping with the low hydro. Had any utility stood before the Commission and said, "we are not making any attempt to replace the lost hydro; we plan to replace that power with market purchases when the time comes," it would have been laughed out of the proceeding. Yet this is exactly the behavior that the Company and Staff's proposed mechanism will model.

For example, if PGE signed a contract in March to cover its position in August, this contract would reduce the likelihood that the company would have to purchase expensive market power in August due to hot weather. The proposed mechanism, however, doesn't acknowledge this contract, and the back-cast MONET run would, instead, dispatch existing PGE resources and purchase power at day-ahead market prices, as if the contract didn't exist.

As it turns out, PGE has signed a number of contracts to fill its position since the RVM. The Company identifies a number of these contracts that relate to this year's low hydro conditions. Exhibit 207 is the Company's response to CUB data request 31. We can think of no reasonable argument why these actual purchases to replace lost hydro should not be included in a mechanism whose purpose is to track hydro variability.

At the PUC hearing, each utility described how the low hydro conditions would impact the utility, and how it planned to fill its short position. No utility suggested it was doing nothing to replace the expected lack of hydro generation. As any prudent utility would, this region's utilities have been trying to fill their short position ahead of time, to not leave themselves unduly exposed to the vagaries of the short-term market which is greatly influenced by short-term weather. The proposed mechanism, however, would expose customers to the vagaries of the market in the calculation of the amount they must pay.

Staff, too, agrees with the general consensus that a prudent utility would use forward contracts as a part of its strategy to replace lost hydro. In Staff's words:

> A prudent utility should deal with lost hydro by, in part, seeking the best possible cost/risk tradeoff to balancing its portfolio of resources and loads with transactions in the forward, balance-of-month, daily, and real-time energy markets. A prudent utility should consider the stochastic nature of market electricity and natural gas prices when considering the expected dispatch of its natural gas-fired assets (e.g., PGE's Beaver and Coyote Springs units) and capacity tolling agreements.

Exhibit 208 – Staff Response to CUB Data Request 2.

Though the utility's actions may or may not be imprudent, customers will be charged as if the utility had been imprudent. If everyone is in agreement about the prudent actions a utility should take, why are we considering a mechanism that assumes imprudent utility behavior?

E. Proposed Mechanism Will Probably Over-Estimate Costs

In presuming imprudent utility actions, the model will also, most likely, overcharge customers for the cost of replacement power. As we mentioned earlier, one would hope that the contracts PGE negotiates and other steps the Company takes to replace its reduced hydro generation would be less costly than market purchases. Why then are customers charged as if the utility were making the most-expensive choice possible? The back-cast MONET run will dispatch PGE's thermal resources at a modeled optimum, but it will presume a full load and not include any contracts the Company may have procured during the months since it became known that hydro conditions would be below normal. The upshot of this design is that the Company would pocket the difference between the cost of its actual prudent strategy for replacing low hydro, and what the back-cast MONET run calculates replacement power costs to be, which would be calculated as if the utility had imprudently taken no steps to fill its position and as if customers had not conserved at all.

Exhibit 209 is an excerpt from ICNU data request 55 to PGE. It shows that, according to the written presentation Mr. Lobdell prepared for the April PUC hearing, PGE estimated that its prudent reduction of its hydro generation estimates in the fall allowed the company to procure some of its replacement power early, saving approximately $6 million in energy costs. PGE should be commended for its prudent response to low hydro conditions. However, the Company should not be allowed to ignore its own actions, and charge customers as if it had acted imprudently.

F. Is It Consistent with the Law and Good Public Policy?

Though this topic will undoubtedly be addressed as a key legal issue in briefs, we think it is relevant to raise here. The language of the statutes in question seems to support what we believe is good policy, historic precedent, and common sense: that power cost adjustments and deferrals track the difference between the projected costs that were used to establish rates and the actual costs incurred – not a modeled approximation of actual costs.

> The term "automatic adjustment clause" means a provision of a rate schedule which provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in <u>costs incurred</u> or revenues earned by a utility…

ORS 757.210 (1). Emphasis added.

> [T]he Commission by order may authorize deferral of the following amounts for later incorporation in rates: … (e) <u>Identifiable utility expenses</u> or revenues …

ORS 757.259 (2). Emphasis added.

Both of these seem to require that actual costs incurred be used for automatic adjustment clauses and deferrals. This also makes a lot of sense from a public policy perspective. In ratemaking, we forecast costs, because we have to. We know that our forecasts will be wrong, but we attempt to set rates such that, overall, they reasonably cover a utility's costs. When implementing an adjustment mechanism or a deferral, circumstances have changed; we now know the actual costs and can use them.

Earlier, we discussed some of the problems associated with the proposed mechanism's use of modeled costs to approximate actual ones. We discussed the fact that load was lower than forecast in January, Exhibit 202, but that the proposed mechanism would charge customers as if that load had been used. Does the theoretical cost of serving January load that didn't exist meet the legal definition of "costs incurred" or an "identifiable utility expense"? If the Company signs a power contract in February to cover low hydro for the summer, but the actual summer prices used by MONET are much higher than those of the contract, does this meet the legal definition of "costs incurred" or an "identifiable utility expense"? As we have said, neither we nor PGE know of any precedent for this sort of mechanism, so these questions have never been answered.

G. Can't Test Proposed Mechanism

As we discussed earlier, the proposed mechanism is unlike other automatic adjustment mechanisms designed to track power costs in that it defers the difference between two sets of modeled costs, as opposed to the difference between modeled baseline costs and actual costs. In addition to the other problems this quirk presents, it also turns out that MONET has not yet been updated to run the back-cast necessary for the calculations that are to be used in this mechanism. Therefore, we cannot test it using past data to see how it compares as a stand-in for actual conditions. Exhibit 210, is CUB data request 29 asking the Company to provide MONET runs demonstrating how the proposed mechanism would have performed in 2002-2004.

No one knows how this might actually work. We certainly don't know. Staff doesn't know. The Company doesn't know. Most importantly, however, the Commission doesn't know, and to implement the proposed mechanism, with the problems that are already clear and presented, without any simulations to get a sense of how the mechanism might perform, seems foolhardy.

IV. Miniature Deadband Is Not Appropriate

The deadband proposed for this mechanism is unreasonably small. Staff argues that a narrower deadband is justified because this proposed mechanism "tracks a narrower set of costs." Staff/300/Galbraith/10. PGE concurs, saying "the stipulated mechanism is limited to only a subset of PGE's power costs and just as importantly, reflects items that are outside of the scope of influence of PGE (i.e., hydro, market electric and gas prices).” PGE/900/Lobdell-Niman-Tinker/17.

A. Proposed Mechanism Tracks A Major Subset Of Power Costs

Though the proposed mechanism was not designed as an all-encompassing power cost adjustment, it is, nevertheless, a pretty major cost adjustment. Hydro variability, market electricity prices, and market gas prices are three extremely significant variables in power costs. Yes, actual load is excluded, as are post-RVM contracts, but – putting aside that these omissions do more harm than good – in terms of wild-cards in forward-looking ratemaking, the proposed mechanism has ‘em covered. Reducing the cost side of the deadband from $40 million to $15 million is not justified by the exclusion of load variability and updated contracts, as Staff witness, Galbraith, contends. Staff/300/Galbraith/10.

B. “Scope of Influence” Is A Red Herring

We do not recall “scope of influence” ever being a central factor in the determination of a deadband. A deadband is established to represent the normal variability that a utility is expected to experience, and the return on equity they get paid to bear that risk. In addition, it is not entirely clear what “scope of influence” is meant to encompass. No, a utility cannot make it rain, but, yes, a utility can enter into prudent contracts to cover its position, it can participate actively to mitigate the environmental factors that may be contributing to the recent down-trend in Northwest hydro production[3], and it can ask its customers to conserve when circumstances warrant … as PGE and other regional utilities did this spring.

Further, we presume the Company did not mean to suggest that load is under its "scope of influence," because load is not reflected in the proposed mechanism. Variables vary; that's what they do. Managing that variability is what utilities are supposed to do. A utility's incentive to manage its position well comes first from the prudence review, not the deadband. The Commission considers how much influence a utility has over a variable when deciding if a utility's decisions were prudent under the given circumstances, not when the Commission decides how much variability a utility should absorb by establishing a deadband.

C. Not Consistent With Past Commission Policy

We discussed past Commission policy at length in our opening testimony, and, though $15 million may be a jump from the Company's original $2.5 million proposal, it is still well below a range we consider reasonable in light of the Commission's order in UM 1071, past deadbands, and past Staff testimony. In OPUC Order 04-108, the Commission rejected PGE's proposal to absorb only 18% of its excess Net Variable Power Costs ($5.6 million), stating that it was "well short of the 250 basis points of return on equity within which we allowed no recovery in UM 995."

In keeping with that decision, Staff, in opening testimony, argued for a deadband of approximately $40 million, representing 250 basis points of return on equity. In stark contrast to that, the $15 million deadband Staff agreed to in the proposed mechanism

[3] "These greenhouse gases … are almost certainly the cause of the increase in Earth's average temperature during the last 50 years. Although it is not yet statistically possible to attribute Northwest warming to the strengthening greenhouse effect, it is very likely that recent warming here too is indeed a result of the accumulation of greenhouse gases." PGE/400/Mote/4.

represents less than 100 basis points of return on equity. It should be remembered that the deadband in PGE's 2001 power cost deferral was $35 million, and the deadband in the mechanism stipulated to in UE 115 for 2002 was $28 million. For further discussion, please see CUB/100/Jenks-Brown/10-12.

D. Proposed Mechanism Makes Deadband Even Smaller

As we described earlier, we don't know how closely the proposed mechanism will mimic actual costs, but because the Company has the ability to prudently reduce its cost of replacement power below what it would pay in the day-ahead market, most likely, the mechanism will over-estimate costs, and, therefore, overcharge customers for the poor hydro conditions. This effectively shrinks the already diminutive deadband, because those over-projected costs will count against the deadband.

For example, if the difference between the Company's actual costs and the back-cast MONET run's estimate of actual costs were $8 million, then the proposed mechanism would overcharge customers by $8 million. This effectively reduces the deadband from $18 million to $10 million, because the mechanism itself included $8 million the Company didn't actually spend.

V. Retroactive Ratemaking Is Bad Policy

Why design an ongoing mechanism, even a two-year one, that violates the traditional prohibition on retroactive ratemaking, when there isn't any need to do so? It is an extremely bad precedent to set, and, as the Company has filed a deferral for this year, UM 1187, there is no need to establish such a precedent, because the Company already has an avenue of recovery for 2005.

A. Retroactive Ratemaking Is Theoretically A Bad Idea

There is a good reason for a general prohibition on retroactive ratemaking. If parties could reach into the past to adjust unfavorable Commission decisions, no Commission rate decision would ever be final. This could wreak havoc on a utility's ability to raise capital, since the utility, and thus its creditors, would never know when it might have to refund past revenue. It could damage the public's perception of, and trust in, utilities and the Commission, by adding volatility to rates and confusing line items to customer bills. It would also, no doubt, increase the already-considerable resources necessary to establish rates, by allowing Commission decisions to be litigated over and over again.

B. When Agreement Reached, Parties Knew PGE Benefited In 2005

Another reason to avoid retroactive ratemaking in this particular case is that the party who will benefit from the proposed mechanism in the first year is already known, and was known at the time the stipulation was reached. An ongoing mechanism should be designed, insomuch as possible, in a neutral environment, isolated from the parties' knowledge as to who might benefit. Though parties may try to remove themselves from their knowledge of current conditions when designing a retroactive mechanism, it is hard to imagine that their knowledge plays no role in their thinking.

The proposed mechanism grew out of settlement discussions on March 3, 2005, and the proposed stipulation was filed on April 11, 2005. The Bonneville Power Administration's runoff forecasts were below average, though barely, as early as the end of December 2004, and declined pretty steadily into March of this year. Exhibit 211. Though the Bonneville forecast has improved somewhat, it remains below average.

Confidential Exhibit 212 shows that the Company's actual hydro generation was down in January and February, and that its hydro forecast for March through the end of the year was also down.

Clearly, when this proposed mechanism was designed and stipulated to, all parties were aware that the Company would benefit from it in the first year. As the proposed mechanism is only in place for two years, it is known that the proposed mechanism will be favorable to PGE for half of the time it covers. Though the effect of this may be small, any ongoing mechanism should be designed on a theoretical basis, without the shadow of known conditions and known financial gain one way or the other.

In addition, as we have already noted, PGE was aware that, not only were hydro conditions low, but loads were down when this mechanism was agreed to. Exhibit 202. By fixing loads at forecasted levels, the mechanism further benefits PGE by guaranteeing revenues associated with projected loads that did not actually exist.

VI. PGE's Rebuttal Badly Misrepresents CUB's Testimony

When PGE filed its testimony in support of the proposed stipulation, it also filed its rebuttal to our earlier testimony concerning their original proposed Hydro Generation Adjustment (HGA). While the debate over the HGA proposal is largely irrelevant, as this new stipulation supercedes it, PGE misrepresented our testimony in a way that requires us to respond. While it is not wildly unusual for a party to exaggerate another party's testimony in order to rebut it, PGE's rebuttal far overshot the exaggeration line and landed deep in misrepresentation territory.

A. CUB Did Not Assert A Systematic Link Between Hydro & Thermal

PGE goes to great length to demonstrate that "there is no systematic link between hydro output and the relationship between electric and natural gas prices." PGE/900/Lobdell-Niman-Tinker/4, emphasis theirs. First of all, we never said there was a "systematic link." We demonstrated a relationship between the Company's hydro generation and its thermal generation, but we certainly never suggested that it was a perfect correlation. Second, for the Company to go to such length to demonstrate no "systematic link," but never acknowledge that there most definitely is a link between hydro generation and thermal generation is disingenuous.

We agree with the Company that there is no well-established relationship between the prices of electricity and natural gas, and that there is not a "systematic link between hydro output and the relationship between electric and natural gas prices." PGE/900/Lobdell-Niman-Tinker/4. We do point out, however, that "a utility with excess low-cost hydro combined with lower-than-projected market prices, would reduce the output of its higher variable-cost generation and replace this with self-generated hydro and lower-cost purchased power." CUB/100/Jenks-Brown/3. PGE's hydro generation interacts with its thermal generation, though, certainly, other significant variables enter into the equation as well. Its diversity of resources gives the Company dispatch options, and to suggest either that there is an exact relationship between hydro and thermal, or, conversely, that there is no relationship whatsoever is ridiculous, and we did neither.

Staff supports our assertion that a utility's hydro generation influences its thermal generation, though certainly not in a formulaic way. Exhibit 213 is Staff's response to CUB data request 8 about the connection between low hydro and thermal generation in which Staff explains that, “Staff believes a portion of reduced hydro output is likely to be replaced with increased output from natural gas fired assets because poor hydro conditions are likely to produce increased spark-spreads, all other things constant.”

In its frenzy to demonstrate this lack of a systematic link, the Company says, “CUB’s graph inexplicably leaves off the last few years of data.” PGE/900/Lobdell-Niman-Tinker/6. A more careful reading of our opening testimony would have provided the Company with an explanation. The graph in our opening testimony, to which Lobdell-Niman-Tinker object, is presented under a section called: “What Actually Happens In A Good Water Year.” The first sentence of that section reads: “To test whether PGE’s HGA would under-refund the value of excess hydro we looked to the 1990s when there were several years of good hydro.” Voila … the explanation the Company couldn’t seem to find.

We weren’t looking at all conditions; we were only looking at good water years with excess hydro. Unlike our discussion of this relationship in low water years, we don’t have MONET runs from the good water years in the 1990s to demonstrate the relationship, “all other things constant.” We didn’t have that baseline, so we did the next best thing. We certainly weren’t claiming that annual changes in hydro and gas-fired production are always inversely related, as Lobdell-Niman-Tinker assert that we did. PGE/900/Lobdell-Niman-Tinker/7. We used data from good hydro years to demonstrate the occurrence of a relationship that we had discussed theoretically in an earlier section. This is a far cry from asserting a systematic link, and it explains quite clearly why the graph covers the period that it does.

B. PGE - Not CUB - Proposed Mechanism Without Actual Gas Prices

"CUB's assumption of constant gas prices leads to erroneous financial conclusions." PGE/900/Lobdell-Niman-Tinker/8. This is flatly untrue. The financial conclusions we drew were based on the HGA that the Company itself proposed which did not account for actual natural gas prices. To suggest that our conclusions were incorrect, when we followed the Company's own proposed mechanism, is absurd.

While it is true that PGE's current proposed stipulation accounts for actual market gas prices, the HGA to which we were responding at the time DID NOT. Lobdell-Niman-Tinker had clearly not forgotten this distinction as they later state, "[t]he HGA *only* tracked the actual variances in hydro generation and valued the excesses or shortfalls at market." PGE/900/Lobdell-Niman-Tinker/15, emphasis added.

To add insult to injury, Lobdell-Niman-Tinker later suggest that it was we who asserted that a proper mechanism should account for actual electricity prices but not natural gas prices: "Q. CUB indicates than an appropriate mechanism would update Monet for actual electric prices, but not actual gas prices (CUB/100, Page 6)." PGE/900/Lobdell-Niman-Tinker/18. We didn't remember saying any such thing, and could find nothing on the cited page, or anywhere else in our testimony, for that matter, to suggest that we had, so we asked the Company to clarify. The response was as follows:

> CUB's discussion on Page 6 of CUB/100 describes updating Monet with actual hydro generation and actual market (electric) prices in order to determine that "PGE's HGA would have led to significantly higher rates…" … This analysis indicates that an appropriate mechanism "would update Monet for actual electric prices, but not gas prices."

Exhibit 214 – PGE Response to CUB Data Request 38.

The Company's reverse logic says that, because CUB performed an analysis to test PGE's proposed mechanism – which the Company had not done – CUB, therefore, indicates that the Company's approach represents an appropriate mechanism. Let us be clear, performing an analysis of the Company's proposed mechanism, an analysis PGE should have included in its initial filing, indicates absolutely nothing about what we think an appropriate mechanism should be. Also note, the quote "would update Monet for actual electric prices, but not gas prices," appeared in PGE's rebuttal[4], not CUB's testimony.

C. CUB Not Incorrect In Showing PGE's HGA Would Overcharge

As described in the previous section, it was PGE, not CUB, who proposed a mechanism that did not update for gas prices. The Company's proposed HGA mechanism only tracked changes in hydro generation and market electricity prices. Our testimony demonstrated that PGE's proposed HGA mechanism would overcharge customers for those changes in hydro and market prices. Whether those overcharges could be offset in a particular year by changes in gas prices is not relevant, because the HGA proposed by PGE at the time did not account for gas prices. For the Company to rebut our opening testimony by including market gas prices – which are included in this stipulated mechanism, but were NOT in PGE's original mechanism – sets the low bar a little lower.

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[4] We mistyped the quote in our data request, though the meaning was not altered. The actual quote from 900/Lobdell-Niman-Tinker/18, reads: "would update Monet for actual electric prices, but not actual gas prices …"

VII. CUB Recommendations

We are addressing two separate filings and two distinct regulatory tools in this testimony, though it addresses a single, retroactive mechanism proposed for both dockets. We have spent the bulk of our pages on the retroactive mechanism agreed to in the stipulation between PGE and Staff. In its order in UM 1071, the Commission suggested that an adjustment mechanism may be an appropriate way to address the Company's concerns about hydro variability. The current proposal, however, and the one which preceded it, are neither just nor reasonable. We're not sure they're even rational.

Both our patience and the schedule of these dockets grow thin, so we recommend the Commission use the Company's already-filed deferral to account for this year's hydro conditions, and reject the proposed power cost adjustment mechanism. The Company can file another deferral next year if conditions warrant, and the parties can address an ongoing power cost adjustment mechanism in PGE's next general rate case, which will be upon us before we know it.

A. CUB's Opening Testimony

In our opening testimony, we said, "we generally agree with PGE that the risk we are trying to address is one associated with hydro, and therefore, a PCA should be limited to hydro and electric prices … [t]he more narrow the scope of a PCA, the less likely the PCA is to have unintended consequences." CUB/100/Jenks-Brown/21. While we stand behind these principles, we are becoming increasingly frustrated with the mechanisms proposed in this docket which attempt to do that. Though we continue to believe a mechanism narrowly designed to track actual hydro power cost variations in a reasonable manner ought to be possible, we recognize that we are no closer to such a mechanism today than we were when this docket was filed.

By not including power contracts or customer conservation efforts that are directed towards addressing low hydro conditions, the proposed mechanism fails to effectively target or accurately reflect the effects of hydro variability. Therefore, as a temporary solution to the problem of hydro variability, we are willing to consider a broader mechanism, similar to the one the Commission approved in UM 1008 & UM 1009.

B. Deferred Accounting Vs Automatic Adjustment Mechanisms

Automatic adjustment mechanisms and deferrals are different tools, they serve different purposes, and, though they can address some of the same circumstances, they should be applied differently. At the most macro level, deferrals are one-time filings, while adjustment mechanisms are ongoing. For this reason, deferred accounting is more often used to address one-time events, while automatic adjustment clauses track variables that can be stochastically modeled. Like any perfect definition, there are grey areas such as severe droughts. While annual hydro variability can be stochastically modeled, hydro conditions at the extreme ends of the bell curve tend to impact customers and the utility in a significant, single-event kind of way.

Also, because they are one-time filings, deferrals tend to be more narrowly defined than automatic adjustment clauses. For example, a deferral for low hydro conditions should not encompass the costs of a generating plant dropping off-line, while a power cost adjustment will often include costs of replacement power for that plant.

An important distinction to customers is that deferrals are inherently one-sided, because the utility's access to information is far greater than that of the customer groups. PGE, for example, has requested a series of power cost deferrals to recover costs related to low hydro in recent years, but never filed a power cost deferral in the 1990s to share their excess revenues associated with abundant hydro. A well-designed adjustment clause, on the other hand, can balance the utility's interests with those of customers.

C. UM 1187 – Use PGE's 2005 Hydro Deferral

Though the Company has in the past filed for hydro-related deferrals that we considered frivolous, in February, hydro conditions were shaping up to be serious indeed. While hydro conditions have improved since then, and may no longer warrant a deferral, PGE has filed a deferral and it can be used for 2005 if the fiscal impact on the utility is material. Despite our reservations about the current materiality of PGE's 2005 hydro conditions, we would support the Commission adopting a deferral mechanism with a deadband and sharing bands similar to those adopted in 2001 for UM 1008 & UM 1009. While this may not be an ideal mechanism, it has been judged to be reasonable in the past, and should meet the utility's and the parties' needs in this docket. It should include:

- A deadband for power cost variances representing an amount above or below 250 basis points of return on equity
- A customer sharing band of 50% for power cost variances representing an amount between 250 and 400 basis points of return on equity
- A customer sharing band of 90% for power cost variances representing an amount above or below 400 basis points of return on equity
- A prudence review

A deadband representing 250 basis point of return on equity was calculated to be about $35 million in 2001. In opening testimony, Staff stated that 250 basis points of return on equity is now approximately $40 million. Staff/100/Galbraith/26. A meaningful deadband of this size would remove our concern as to the fading severity of this year's hydro conditions, and whether or not the Company's power costs would be high enough to warrant a deferral.

The customer sharing bands used in UM 1008 & UM 1009 were 50% of cost variances between 250 and 400 basis points of return on equity, and 90% of cost variances above 400 points. The Commission deemed these sharing bands to be just and reasonable in 2001, and we have seen no evidence suggesting that they were not[5]. Therefore, to share the risk of variability beyond a normal range – represented by the deadband – we consider these sharing bands appropriate to use in this case as well.

A prudence review before amortization is an important regulatory check. The review would focus on whether the incurred power costs were part of a prudent response to low hydro. This is more than simply a review of whether the actions themselves were prudent, but whether they were prudently incurred in response to low hydro. For example, if PGE has a major power plant outage, over- or under-projects its load significantly, or incurs significant excess costs for some other reason, those costs should be identified and excluded from the deferral as-filed. If such an event happens and is material, the Company may file to amend its deferral application to include such costs.

If PGE's power costs are more than $40 million above forecast, and this increase is despite prudent management of low hydro conditions, then CUB would support recovery under this proposed mechanism.

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[5] PGE has argued that this year is different because of the cumulative earnings impact of multiple years of low hydro conditions. PGE's 2004 Results of Operations filed yesterday, however, show a 2004 return on equity of 10.28% and a normalized return on equity of 11.66%.

D. UE 165 - Reject Proposed Power Cost Adjustment Mechanism

The Commission should reject the proposed power cost adjustment mechanism. It has numerous problems, as we have discussed, it sets dangerous precedents, and it is a bad deal for customers.

i. 2005 Is Covered & If Need Be, 2006 Can Be Covered Too

This proposal, as put forward, doesn't really qualify as an automatic adjustment mechanism, though it does set some disturbing precedents. As we described earlier, when the mechanism was agreed to, we already knew, and the Company most certainly knew, in whose favor the mechanism would go in 2005. So, as a neutral mechanism, we're really only looking at 2006. Designing a one-year power cost adjustment on the fly seems reckless. The Company is planning to file a general rate case in 2006, and this is an appropriate place to present a power cost adjustment mechanism. There is no need to do anything for 2006 power costs now. If hydro conditions are bad, the Company can file another deferral as it has done in the past.

ii. If Commission Feels 2005 Must Be Covered, Use Our Proposed Deferral

If the Commission feels that the Company must have something in place for 2006, then we recommend providing our recommended deferral from UM 1187 for the Company for 2006, but, because it is forward-looking the deadband should be asymmetrical, ranging from 250 basis points of return on equity for positive power cost variations (customer payment) to 125 basis points of return on equity for negative power cost variations (customer credit). This is to account for the asymmetry of the fiscal impact of hydro conditions.

> Q. Why are the outcomes skewed such that less hydro generation has a greater adverse effect than more hydro generation has a positive effect?
>
> A. The basic economic principles of supply and demand cause the skewed outcomes. Prices are higher when there is a shortage of hydro generation, and lower when there is "excess" hydro generation.

PGE/100/Lesh/10.

The customer sharing band should likewise be adjusted for negative power cost variations to 50% of amounts ranging from 125 to 200 basis points of return on equity and 90% of amounts beyond 200 basis points.

iii. Proposed Mechanisms Must Be Tested

It is becoming painfully clear that the process of designing a power cost adjustment mechanism must include testing the mechanism, to the extent practicable, with past data to see what the results of the mechanism would be under actual conditions. The first mechanism proposed in this docket, as we demonstrated, would have overcharged customers. The second involves an update to MONET that hasn't been completed yet, and so cannot be tested. However, the issues raised in this testimony suggest that the mechanism proposed in this stipulation may behave in peculiar, unintended ways, and that its results – numerical, political, and legal – will not be easy to predict without quantitative support.

The complexities and variable interactions involved in power costs are such that it is not always easy to foresee how a regulatory mechanism will turn out when applied to actual data. In UE 115, the Commission cited the expectation that the PCA would lead to customer credits as market electricity prices decreased, but instead, the decrease was dwarfed by the revenue adjustment resulting from customers' reduced usage.

Exhibit 204. Of course, even running a proposed mechanism on past data won't tell you what will happen under future circumstances, but at least the Commission would have concrete examples, as well as theoretical arguments, upon which to base its decision. While a dry run won't provide perfect foresight, at least it doesn't leave the parties flying blind.

E. Investigate The Least-Cost Approach To Hydro Variability

In our opening testimony in UE 165, we recommended that the Commission and the parties examine the ways hydro variability can be managed in a least-cost, least-risk manner, rather than the current focus on cost recovery. CUB/100/Jenks-Brown/24. We continue to believe that there is too much focus on who pays what, and not nearly enough focus on the best approach to minimizing the cost of hydro variability.

May 10, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated April 28, 2005
Question 030

Request:
Traditionally, deferrals for a specific incident such as low hydro have been quantified by calculating the difference between the original, theoretically modeled costs and the actual costs as they occurred for the incident in question. Please provide all cases that the company knows of where the Commission has allowed deferral of an amount calculated as the difference between the original, theoretically modeled cost and another theoretically modeled cost – even though updated with some actual variables – as is proposed in this stipulation.

Response:

PGE objects to this request on the basis that it is unduly burdensome. PGE has not reviewed all deferrals and adjustment mechanisms. Without waiving objection, PGE replies as follows:

The Commission has broad discretion in determining deferral methodologies. Past deferrals have not been "uniform," but rather have been fitted to particular circumstances. The structure of the stipulation between OPUC Staff and PGE is no different; it deals with a specific set of circumstances over a specific period of time.

Two examples that contain the elements described in the question are the following:

1) The Commission granted PGE an IT-related deferral in Docket No. UM-1131. The Commission based this deferral on the difference between base and "actual" revenue requirements for certain IT capital expenditures. The base revenue requirement was based on an expected measure of 2000-2002 capital costs, and the capital structure and rates of return approved in Docket UE-115. The "actual" revenue requirement was based on actual 2000-2003 capital costs, and the same capital structure and rates of return

approved in Docket UE-115. In other words, we did not update capital structure and rates of return, which are elements of the revenue requirement calculation. Therefore, the "actual" revenue requirement was "another theoretically modeled cost – even though updated with some actual variables."

2) PGE's Save All Value Equitably (SAVE) energy efficiency-related mechanism, approved by the Commission in Order No. 91-98, compared the capitalized cost and revenue implications of energy efficiency activity levels assumed in base rates with the capitalized cost and revenue implications of "actual" activity levels. Base rates were set in Docket UE-79, using the capital structure and rates of return approved in that Docket, and theoretically modeled energy savings associated with assumed program activity levels. The measure of "actual" revenue requirement was based on the capital structure and rates of return approved in Docket UE-79. In other words, we did not update capital structure and rates of return, which are elements of the revenue requirement. In addition, the "actual" revenue requirement was based on the theoretically modeled energy savings associated with actual program activity levels, rather than on (literally) actual energy savings. Therefore, the "actual" revenue requirement was "another theoretically modeled cost – even though updated with some actual variables." We updated program activity levels to actuals. However, we continued to assume the capital structure and rates of return approved in Docket UE-79 and the theoretical relationship between program activity levels and actual energy savings.

Excerpts of Load Data from CUB Data Request 32

	ACTUAL	FORECAST	DIFFERENCE AMT	DIFFERENCE %
January-05				
MWH SOLD				
RESIDENTIAL				
MWH ACTUAL	837,952	865,994	-28,042	-3.2
SALES AT ACTUAL WEATHER				
FIRM SALES	1,815,985	1,832,810	-16,825	-0.9
February-05				
MWH SOLD				
RESIDENTIAL				
MWH ACTUAL	732,733	810,430	-77,697	-9.6
SALES AT ACTUAL WEATHER				
FIRM SALES	1,701,243	1,764,376	-63,133	-3.6
March-05				
MWH SOLD				
RESIDENTIAL				
MWH ACTUAL	647,196	708,402	-61,206	-8.6
SALES AT ACTUAL WEATHER				
FIRM SALES	1,589,590	1,646,908	-57,318	-3.5
April-05				
MWH SOLD				
RESIDENTIAL				
MWH ACTUAL	593,303	619,184	-25,881	-4.2
SALES AT ACTUAL WEATHER				
FIRM SALES	1,491,500	1,542,418	-50,918	-3.3

April 11, 2005

TO: Bob Jenks
Portland General Electric Company

FROM: Maury Galbraith
Oregon Public Utility Commission

CITIZENS' UTILITY BOARD OF OREGON
UE 165
Staff Response to CUB Data Request No. 007
Dated March 28, 2005
Question 007

Request:

If PGE loads in 2005 are lower than modeled in the RVM, due to a combination of a mild winter and customers responding to call for conservation, why does Staff believe it is appropriate under the stipulation to charge customers a deferral amount that reflects usage in excess of what was actually used?

Response:

Staff believes the stipulation reasonably excludes customer loads from the temporary adjustment mechanism. The question anticipates lower loads due to a mild winter and customer conservation. Another possibility is higher loads due to an extreme summer and increased economic activity. The stipulation adjustment mechanism excludes both the risks and rewards associated with tracking customer loads.

Excerpt – UE 137 CUB Testimony

II. The Current PCA has Failed.

According to the Oregonian, since last fall's unprecedented increase in rates, PGE's "residential customers pay more for electricity than consumers of any other large utility in the Northwest." Exhibit 103. The current PCA was supposed to be a tool to bring down these power costs:

> "The Commission worked with PGE and customer groups to adopt a Power Cost Adjustment (PCA) mechanism that will lower rates if power costs decline. Conversely prices could go up if wholesale prices rise."
>
> --PUC news release, August 31, 2001 Exhibit 104.

> "In addition, the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline."
>
> --PUC Order No. 01-777 page 2.

This is not the way it worked. Wholesale prices did not rise, yet the PCA adopted in UE 115 requires a rate hike expected to be more than $43 million. Exhibit 105. Instead wholesale prices declined yet there is no rate relief for residential customers from the PCA. In spite of this failure of the current PCA to work as advertised, PGE comes right back and proposes the same thing. This is similar to a three-card monte operator asking you to play again (in PGE's case, three-card Monet).

Power costs did decline. According to the Company, variable power costs declined by $18.5 million. However, because the PCA requires that customers reimburse the Company for lost revenue, and the Company energy revenues declined by $102 million, the result is that the current PCA requires that customer pay the $43 million plus interest.

Exhibit 105. It should be noted that nowhere in PGE's testimony in UE-115 did the Company "discuss the effects of a change in the PCA due to a change in customer usage." Exhibit 106. Instead of creating a mechanism that would lower rates when power costs decline, we got a mechanism that would raise rates when customers cut back on usage.

There are several reasons that customers cut back on usage:

1. The economy. In UE 115, while the Company regularly updated their Monet runs and power cost projections, it did not update its load forecast after it filed rebuttal testimony in February 2001. At that time the Company believe the economy was about to come roaring back. By the time the PCA was designed in July 2001, the Company should have realized this economic forecast was wrong and that their load forecast needed to be updated. The Company failed to do so. It failed to do so again in September 2001 when the Company updated its power costs projections. While the Company was failing to update its forecast, customers through the PCA were taking much of the risk of this failure.

2. Rate shock. Customers reacted to the rate shock of a 31% to 50% increase in rates by cutting back on usage. The product PGE sells became unaffordable for some uses for some customers, so the customers stopped purchasing as much of PGE product. While the Commission ruled in UE 115 that it could not take rate shock to customers into effect when setting rates, the PCA insulated the Company from the effects of this rate shock on customers' purchases.

It is difficult for customers to accept that the Commission will not do anything to protect customers from rate shock, but that customers' rates must increase again in order to protect the Company from customers' own actions take to protect ourselves from rate shock.

3. Energy Efficiency Programs. The Company aggressively and successfully pursued energy efficiency in 2001 but did not include these efforts in their load forecast. For example at the UE 137 Load forecast workshop the Company stated that customers saved 12 aMW by installing 1.8 million compact fluorescent light bulbs (CFLs). The Company was sending out coupons for CFLs nearly every month during the year. However, because the first mailing happened soon after the Company's February rebuttal, which was the last time the Company updated its load forecast, the Company did not take into account this program. By the time the PCA was designed the Company had mailed out a ton of coupons. By the time the Company updated its power costs in September, it knew customers were redeeming these coupons and this was reducing the Company's load. But the Company failed to take it into account. Customers believed that they were lowering their bills when they installed CFLs, but this PCA is allowing the Company to raise rates to recover the lost revenue due to customers redeeming the coupons that the Company sent.

The Company took a risk by not updating its load forecast as it purchased power for 2002 and updated its power cost model. But the PCA insulated the Company from this risk. At no point in UE 115 was there a serious discussion of this risk and the possible effects on rates. Customers were led to believe that PCA would lower rates when the wholesale power costs declined without knowing that the PCA was likely to raise rates because the economic recession, the effects of rate shock and the Company's own energy efficiency programs were driving down demand for energy and the PCA placed much of the risk of this on customers.

CUB supported the PCA because we believed it was balanced, fair and that the Company's power cost situation was "unique, given its exposure to the wholesale energy market in order to serve its retail customers and the current uncertainty and volatility in the wholesale energy market." OPUC order 01-777, Appendix D, page 5. When we signed the stipulation, we knew the Company was aggressively pursuing energy efficiency and that the economic recession was continuing, but we did not know that the Company's load forecast was ignoring these realities. We now know that because the Company was ignoring what was happening to its load forecast, the PCA that we supported was practically guaranteed to be an additional rate hike on customers. In addition, the uncertainty and volatility in the wholesale energy market has changed dramatically since the collapse of PGE's corporate parent, Enron.

In a letter to residential customers last Fall, Peggy Fowler promised a rate reduction when wholesale power costs fell, but instead we are being promised a 0.9% decrease in base rates and a significantly larger surcharge caused by the current PCA. CUB cannot continue to support the PCA that was enacted in UE 115. We will not fall for that again. But this is immaterial because the wholesale market has changed and a PCA is not necessary.

PR 36 05

FOR IMMEDIATE RELEASE:
THURSDAY, March 24, 2005
CONTACT: Ed Mosey (503) 230-5131

Dry weather prompts calls for wise use of energy
Saving energy will help reduce future rate increases

PORTLAND, Ore. – The Bonneville Power Administration, regional utilities and public interest groups today asked Northwest residents to help combat the economic effects of a dry winter by efficiently using electricity this spring and summer.

Another winter of low precipitation makes six in a row -- the lowest cumulative runoff on record, meteorologists report. At a press conference today, representatives of Clark Public Utilities, Northwest Power and Conservation Council, Northwest Requirements Utilities, PacifiCorp, Portland General Electric, the Public Power Council, Puget Sound Energy, several conservation groups and BPA called on Northwest consumers to be especially careful in their use of electricity this year.

Barring unscheduled plant outages or other unforeseen circumstances, the region's utilities expect to have enough electrical generating capability to meet demand. The primary effects will be financial. Low precipitation is reducing hydro system performance for utilities and suppliers in the region, which increases power purchases from other, more costly sources. Low water in rivers is also shrinking expected surplus sales revenues. All of this puts upward pressure on rates.

BPA Administrator Steve Wright said: "Last year we reduced rates 7.5 percent but notified the region that the biggest variable affecting rates going forward would be water and markets. The weather is not cooperating. We can't do anything about the weather, but we can do something about how much energy we use."

All Northwest utilities rely on hydropower for some portion of their electrical supply. When water conditions are average or better, BPA and the other utilities sell excess energy in surplus markets and use the revenue to help hold down rates for Pacific Northwest customers. To the extent that sales are down due to low water, revenues are falling short of projections.

Utilities also must turn to the wholesale market in some months to purchase needed power, and prices there are up. Although the addition of gas-fired turbine generators in the region since the drought of 2001 has helped beef up supply, reliance on gas-fueled combustion turbines at a time when natural gas prices are extremely high increases costs.

"Conservation makes sense during all water conditions," said Melinda Eden, chair of the Northwest Power and Conservation Council. "During a drought it becomes even more important. Conservation is the most important way to meet future electricity demand in the Northwest and can help reduce the future cost of electricity for all consumers. It also offers environmental benefits – there are no toxic emissions. And by reducing demand from the hydropower system, we save water that can help salmon and steelhead migrate rivers."

Here are some steps that the public can take to help save energy and dollars this spring and summer.

- Turn off computers, appliances and lighting when not in use.
- Insist on Energy Star models when buying electrical products.
- Install compact fluorescent lights.

Joining Wright of BPA were: Bob Jenks, executive director, Citizens' Utility Board of Oregon; Carol Curtis, commissioner, Clark Public Utilities; Margie Harris, executive director, Energy Trust of Oregon; Patrice Thramer, director of marketing, Northwest Energy Efficiency Alliance; Melinda Eden, chair, Northwest Power and Conservation Council; Geoff Carr, Northwest Requirements Utilities; Kevin Lynch, vice president, PacifiCorp; Jim Piro, chief financial officer, Portland General Electric; and Jerry Leone, executive director, the Public Power Council.

For information on ways you can save energy, contact your local utility or see links below:

Bonneville Power Administration, Ed Mosey, 503-230-5131, http://www.bpa.gov/
Citizens Utility Board of Oregon, Bob Jenks, 503-227-1984, bob@oregoncub.org
Clark Public Utilities, Mick Shutt, 360-992-3238, http://www.ClarkPublicUtilities.com
Northwest Energy Efficiency Alliance, Patrice Thramer, marketing director, pthramer@nwalliance.org
Northwest Power and Conservation Council, John Harrison, 503-222-5161, jharrison@nwcouncil.org
PacifiCorp, Dave Kvamme, 503-813-7279, http://www.pacificpower.net/Navigation/Navigation1843.html
Portland General Electric, Scott Simms, 503-464-7342, http://www.portlandgeneral.com/home/energy_savings
Public Power Council, Kevin O'Meara, 503-232-2427, http://www.ppcpdx.org/
Puget Sound Energy, Grant Ringel, 888-831-7250, http://www.pse.com/yourhome/waystosave/index.html

# # #

Northwest Governors Call for Wise Use of Electricity in Response to Low Water in Northwest Rivers

Statement of Gov. Brian Schweitzer of Montana:
"When power supplies are short and market are prices high, the best ways to hold down rates and individual power bills are to conserve energy and pray for rain"

Statement of Gov. Christine Gregoire of Washington:
"I support the Bonneville Power Administration and the utilities in their efforts to save energy and water. Conservation is always a good idea, especially when we are facing a drought."

Statement of Gov. Ted Kulongoski of Oregon:
"We must each do our part to help prevent Oregon's water shortages from escalating to water emergencies, and energy conservation is a strategy that we can – and should – all adopt to help meet the needs of Oregon's communities this summer. Not only do consumers win with reduced energy costs – but we save critical water for our fish and agricultural needs."

Statement of Gov. Dirk Kempthorne of Idaho:
"We in the Pacific Northwest have been blessed with resources that have provided us with abundant, inexpensive energy. As this six year drought continues, we must do everything we can to protect and conserve those resources. Please be mindful of your energy use and conserve when possible."

# # #

April 11, 2005

TO: Bob Jenks
Portland General Electric Company

FROM: Maury Galbraith
Oregon Public Utility Commission

CITIZENS' UTILITY BOARD OF OREGON
UE 165
Staff Response to CUB Data Request No. 005
Dated March 28, 2005
Question 005

Request:

The Governor of Oregon joined the Governors of Washington, Montana, and Idaho, as well as BPA, PGE, other utilities, and CUB to call upon customers to conserve energy in order to "help combat the economic effects of a dry winter" and the lack of hydro. Does Staff support the call for retail customers to conserve energy?

Response:

Yes.

April 1, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated March 15, 2005
Question 019

Request:

In regard to 2005 hydro conditions:

a. What is PGE's strategy for dealing with this year's low hydro condition?

b. Has the Company made any purchases to replace projected lost hydro conditions?

c. If so, for what period and at what price?

Response:

a. PGE manages the variability of its hydro resources in the context of its overall power supply portfolio. As forecasted changes in hydro production are estimated, PGE adjusts its net portfolio position and assesses the need to make incremental purchase or unit dispatch decisions. These decisions will be based on an adjusted net portfolio position that also takes into account changes in unit dispatch prices, load estimates, market purchase and sale activity, etc.

For 2005, PGE added length, particularly in the spring run-off season, to its net portfolio in an effort to offset estimated below normal hydro conditions that were being forecasted based on early indications suggesting the prospect for an "El Nino" winter. Further, later in the fall of 2004, as estimates continued to indicate a further decline in hydro production for 2005, PGE continued to review its overall power supply portfolio and make additional incremental purchases to meet customer's energy needs as necessary.

b. Yes. Attachment 19-A provides an electronic copy of the purchases that PGE has made through March 16, 2005 that were specifically identified as replacement energy due to declining hydro conditions. In addition, because PGE manages its power supply position on a net portfolio basis, not all transactions that may have a root cause related to hydro conditions are labeled as such due to other position influencing factors such as changes in natural gas prices, unit dispatch prices, loads, etc. that can occur at the same time. Attachment 19-A is confidential and subject to the Protective Order in this docket (OPUC Order 04-406).

c. See PGE's response to part b) above

2005 Term Transactions Coded as Hydro -- Through 4/30/05

COUNTERPARTY	STARTDTE	ENDDTE	TICKETNO	DEAL#	TRANS_DATE	TRANSTYPE	LOCATION	QTY	ON/OFF	DEALPRICE	CODE

Public Version of
Confidential Exhibit

CUB/207
Jenks-Brown/2

April 11, 2005

TO: Bob Jenks
Portland General Electric Company

FROM: Maury Galbraith
Oregon Public Utility Commission

CITIZENS' UTILITY BOARD OF OREGON
UE 165
Staff Response to CUB Data Request No. 002
Dated March 28, 2005
Question 002

Request:

PGE is currently estimating that it will have 20% less hydro than was expected for this year. How does Staff believe a prudent utility should deal with this lost hydro?

Response:

A prudent utility should deal with lost hydro by, in part, seeking the best possible cost/risk tradeoff to balancing its portfolio of resources and loads with transactions in the forward, balance-of-month, daily, and real-time energy markets. A prudent utility should consider the stochastic nature of market electricity and natural gas prices when considering the expected dispatch of its natural gas-fired assets (e.g., PGE's Beaver and Coyote Springs units) and capacity tolling agreements.

Excerpt From PGE Response To ICNU Data Request 55

Lobdell – 4/5/05 OPUC Drought Meeting Talking Points

Plans for Dealing with hydro shortage:

1. **To manage the volatility** of our hydro energy position, PGE Power Operations constantly monitors market fundamentals. As we reviewed these **fundamentals in the fall of last year** we noticed the existence of the El Nino condition and began gradually reducing the amount of estimated hydro generation in our portfolio. This **adjustment allowed us** to purchase some of our replacement energy in advance of increasing market price levels therefore reducing our replacement energy cost by approximately $6 mm. **We continue to monitor** these market fundamental [s] in an effort [to] minimize the power costs for our customers.

May 10, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated April 28, 2005
Question 029

Request:
Please provide MONET runs demonstrating how the proposed mechanism would have worked in 2002 – 2004.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Without waiving its objection, PGE replies as follows:

PGE has not completed the enhancements to Monet that are necessary to implement the stipulated mechanism. When PGE finishes its modifications, we will provide a copy of the enhanced Monet model to all parties.

PGE's response to part (b) of CUB Request No. 007 provides a comparison of the final 2003 RVM Monet model run, and a run that incorporates actual hydro production, actual electric prices, and actual gas prices. However the "actuals" run does not include the necessary Monet model enhancements. PGE has not yet completed these enhancements.

May 27, 2005

BONNEVILLE POWER ADMINISTRATION

JANUARY-JULY 2005 RUNOFF VOLUME FORECASTS

		GCL		LWG		TDA	
Date	(Forecast)	MAF	%	MAF	%	MAF	%
12/17	(Dec MM)	63.8	101	26.4	88	102.0	95
12/30	(Jan EB)	60.4	96	22.9	76	92.9	87
1/7	(Jan FF)	57.2	91	20.7	69	85.6	80
1/20	(Jan MM)	59.6	95	20.8	69	87.9	82
1/28	(Feb EB)	59.5	95	18.6	62	84.5	79
2/7	(Feb FF)	57.2	91	18.0	60	82.4	77
2/18	(Feb MM)	52.3	83	15.8	53	74.0	69
2/25	(Mar EB)	50.6	80	14.9	50	71.2	66
3/8	(Mar FF)	50.5	80	14.6	49	70.7	66
3/18	(Mar MM)	49.4	79	13.3	44	67.7	63
4/1	(Apr EB)	53.7	85	15.7	52	75.1	70
4/8	(Apr FF)	52.2	83	15.7	52	73.8	69
4/22	(Apr MM)	53.0	84	16.2	54	75.3	70
4/29	(May EB)	52.5	83	15.7	52	74.2	69
5/6	(May FF)	52.2	83	16.5	55	74.7	70
5/20	(May MM)	53.9	86	18.6	62	80.2	75
5/27	(June EB)	54.3	86	19.4	65	80.9	75

GCL: Grand Coulee **LWG:** Lower Granite **TDA:** The Dalles
EB: Early Bird **FF:** Final **MM:** Mid Month

Source: NWS-RFC & USDA-NRCS
%=Percent of 1971-2000 Normals

Public Version of
Confidential Exhibit

PGE 2005 HYDRO GENERATION
Forecast as of 3/4/2005

	Actual / Forecast (MWh)	RVM (MWh)	Actual - RVM (MWh)	
Jan				Actual
Feb				
Mar				Forecast
Apr				
May				
Jun				
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Total				

May 13, 2005

TO: Bob Jenks
Portland General Electric Company

FROM: Maury Galbraith
Oregon Public Utility Commission

CITIZENS' UTILITY BOARD OF OREGON
UE 165
Staff Response to CUB Data Request No. 008
Dated April 28, 2005
Question 008

Request:

In response to CUB DR 4, Staff states that "a portion of the reduced hydro output is likely to be replaced with increased output from natural gas fired assets." Why does Staff believe that a portion of reduced hydro output is likely to be replaced with increased output from natural gas fired assets?

Response:

Staff believes a portion of reduced hydro output is likely to be replaced with increased output from natural gas fired assets because poor hydro conditions are likely to produce increased spark-spreads, all other things constant. Staff believes increased spark-spreads are likely because northwest hydro conditions and northwest spot market electricity prices should exhibit a stronger association than northwest hydro conditions and northwest spot market natural gas prices.

May 10, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated April 28, 2005
Question 038

Request:

PGE claims (PGE/900/Lobdell-Niman-Tinker/18) that "CUB indicates that an appropriate mechanism would update Monet for actual electric prices, but not gas prices (CUB/100, page 6)." We are unable to identify where on that page, or any other page, we suggest that an appropriate mechanism would update Monet for actual electric prices, but not gas prices. Please identify the specific quote and/or quotes that PGE is citing.

Response:

CUB's discussion on Page 6 of CUB/100 describes updating Monet with actual hydro generation and actual market (electric) prices in order to determine that "PGE's HGA would have led to significantly higher rates …" CUB performed this analysis using PGE's Monet runs from UE-115 and UE-139 and then updating certain inputs – "actual hydro generation and actual market prices." CUB did not update gas prices. This analysis indicates that an appropriate mechanism "would update Monet for actual electric prices, but not gas prices." Examples from CUB's discussion are:

"MONET, the model PGE uses to project annual power costs, dispatches resources based on load, market prices, and available resources. We can use MONET to compare PGE's power cost projections from its 2002 and 2003 RVM calculations to what PGE's power costs would have been under the exact same conditions except for updating the MONET run with actual hydro generation and actual market prices." (CUB/100, Page 6, Lines 8-12) "Market prices" here refer to market electric prices only. CUB then goes on to say:

"This comparison shows, by holding all variables except hydro and market prices constant, how MONET dispatches PGE's resources differently to account for changes in these two factors." (CUB/100, Page 6, Lines 12-14) The "two factors" are hydro and market electric prices, i.e. not hydro and market electric and gas prices. Further in the discussion on Page 6 of CUB/100, CUB states:

"CUB Exhibits 106 and 107 are these MONET runs updated with actual hydro generation and market prices. The results show that thermal resources are dispatched to replace some of the hydro shortfall and minimize power costs." (CUB/100, Page 6, Lines 19-22) CUB Exhibits 106 and 107 incorporate actual hydro generation and market electric prices, but not actual gas prices.

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CERTIFICATE OF SERVICE

I hereby certify that on this 2nd day of June, 2005, I served the foregoing Surrebuttal Testimony of the Citizens' Utility Board of Oregon in docket UE 165 & UM 1187 upon each party listed below, by sending a non-confidential version via email and U.S. mail, postage prepaid, and by sending a confidential version to the appropriate parties as identified on the service list by U.S. mail, postage prepaid, and upon the Commission by emailing a non-confidential version and by sending 6 confidential copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

Jason Eisdorfer #92292
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