BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 165

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC,	)
	)
Application for a Hydro Generation Power Cost Adjustment Mechanism.	)
	)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

February 14, 2005

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Our names are Bob Jenks and Lowrey Brown, and our qualifications are listed in CUB Exhibits 101 and 102 respectively.

I. Introduction

CUB recommends that the Commission reject PGE's proposed Hydro Generation Power Cost Adjustment Mechanism (HGA). It is poorly thought out, has little analytical support, and would require customers to pay more than 100% of the cost of replacing low hydro. While there are problems associated with hydro variability, this proposal is not even in the ball park of a fair solution.

In our testimony, we will provide analysis of PGE's proposed mechanism that clearly demonstrates that it does not meet a just and reasonable threshold, we will discuss PGE's approach to the problem, we will address why we believe that PGE is not addressing the correct issues, and finally, we will recommend what the Commission should do in this docket.

II. PGE's Proposed Hydro Generation Adjustment

In a word: Disappointing. We have been talking about this issue for several years, yet PGE has proposed a mechanism which over-charges customers in bad hydro years, under-refunds to customers in good years, and shifts essentially all risk associated with hydro variability onto customers. PGE's mechanism also has the narrowest of dead-bands, and no sharing-band; the Company must know their proposal is not even close to acceptable for CUB or any other party. In addition, PGE fails to provide any real analysis of their proposal, and how it addresses the problem of hydro variability.

First, let us describe PGE's mechanism. It would identify any variation in hydro production, price that variation at Mid-C prices, add in a percentage for wheeling charges and line losses, and, after an insignificant $2.5 million dead-band, shift 100% of the responsibility for these variations onto customers. PGE/100/Lesh/4. PGE is not proposing a Power Cost Adjustment (PCA) that tracks all changes in costs, but instead is focused on the costs associated with two elements: hydro variability and wholesale electric prices, which the Company argues are related to hydro variability.

A. It Is Neither Just Nor Reasonable

The rates produced by PGE's proposed HGA would be neither just nor reasonable. To understand why, we first begin with a theoretical discussion of how the mechanism would work under good and bad hydro conditions, and how a prudent company would simultaneously respond. For our theoretical discussion we accept the following:

- The goal of the HGA is to deal only with the effect of variation in hydro production, and not changes in fuel prices, transmission, loads, or other costs.
- As the variation in hydro production can be shown to affect market prices, the mechanism should account for the effect of these market price changes.

i. What Theoretically Happens In A Good Hydro Year

Under PGE's mechanism, when hydro is plentiful, there will be additional hydro generation, causing market prices to fall. The mechanism values this excess hydro by pricing it at actual Mid-C prices. If a utility's response to excess hydro and the corresponding low market prices were simply to sell the excess hydro at market prices, then the utility would be imprudent.

Instead, 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. PGE's hydro mechanism assumes a company would continue to produce power when the variable cost of that power is greater than market prices, even though the company has excess hydro generation available to replace that more-expensive generation. A prudent company, however, would use the excess hydro to replace generation that costs more than this new, lower market price.

ii. What Theoretically Happens In A Bad Hydro Year

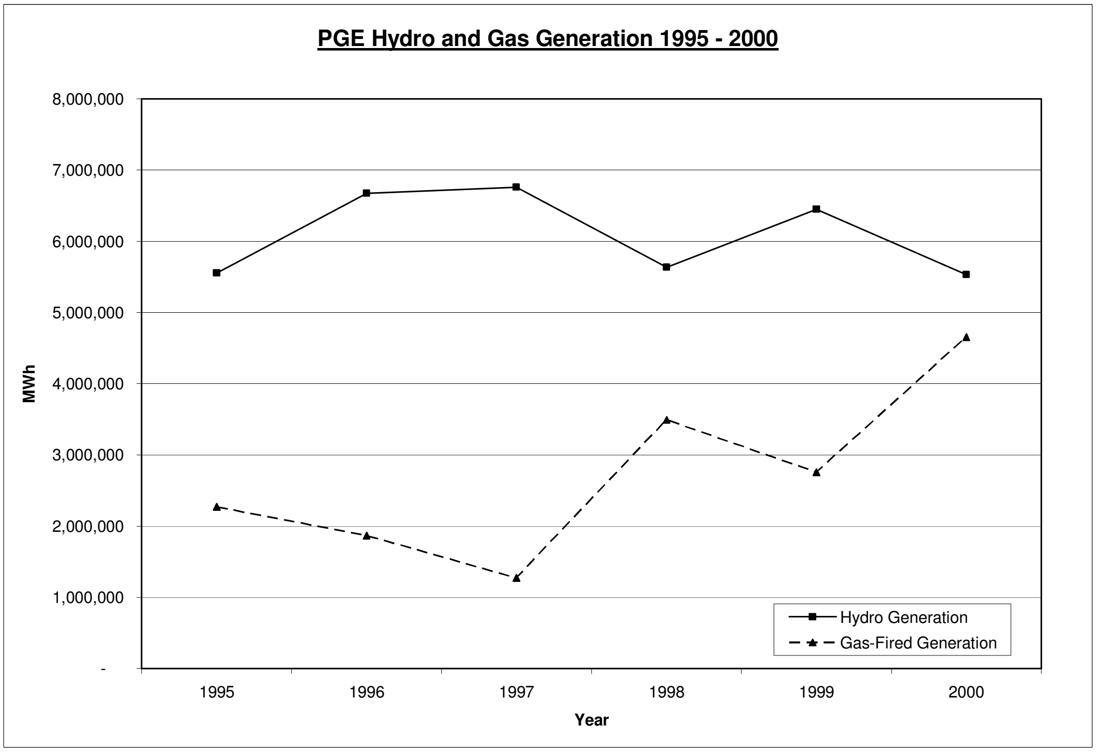
Under PGE's mechanism, when hydro generation is scarce, market prices will go up. The mechanism likewise values the lost hydro by pricing it at Mid-C prices, under the assumption that the utility will simply replace its lost hydro with market purchases. Again, if this were how a utility actually responded, that utility would be imprudent. A utility has a variety of resources that it can use to offset the cost of high prices and low hydro.

Higher market prices make a utility's marginal units more cost-effective, and a prudent utility will use these units to replace the lost hydro, as long as it can do so at a cost below the new, higher market price. Maintenance schedules of other plants might be adapted in a manner as to reduce the need to purchase power at the costliest times. A utility can purchase hedges, such as the two capacity tolling agreements PGE signed this year which would offer power under condition likely to be triggered by a hydro shortfall. In the event of a severe drought, a utility might even appeal to its customers to reduce their power usage.

PGE's hydro mechanism assumes that all lost hydro is replaced at market prices, when market prices actually represent the maximum cost the utility could pay only if it could identify no less-costly way to replace the lost generation. By utilizing its other generation resources and hedges, the utility would have other, less costly ways to replace some of this lost generation. By not accounting for these lower-cost ways of replacing lost generation, PGE's mechanism would allow the Company to over-collect the cost of low hydro. The result would be a mechanism that does not meet a just and reasonable test.

iii. What Actually Happens In A Good Water Year

To test whether PGE's HGA would under-refund the value of excess hydro we looked to the 1990's when there were several years of good hydro. PGE responded to this excess hydro, just as our theory predicts, by reducing the output of Coyote Springs and Beaver, and replacing this power with lower-cost hydro and cheaper market purchases. Had it been in place at the time, PGE's proposed HGA would have missed this effect, and customers would have been shortchanged in receiving the benefit of the good hydro.



This graph, which comes from data in CUB Exhibit 103, shows hydro production and gas-fired production in the late 1990s. This is after Coyote Springs came on line, and includes three years, 1996, 1997, and 1999, when hydro production was well above average. It clearly demonstrates the relationship between good hydro conditions and the use of gas-fired resources. As more hydro generation became available, PGE scaled back its use of its marginal thermal resources and replaced it with the excess hydro. In 1997 PGE used the most hydro generation and the least gas-fired generation. In 2000 the Company used the least hydro generation and the most gas-fired generation. PGE's proposed hydro mechanism does not account for the Company's use of excess hydro to replace gas-fired resources.

iv. What Actually Happens In A Bad Water Year

Determining the effect of bad hydro conditions and higher market prices is easier than showing the effect of good hydro, because we have annual power cost projections using average hydro from PGE's RVM to act as a baseline. In both 2002 and 2003, there were reductions in available hydro and a concurrent increase in market prices. It turns out that PGE's HGA would have led to significantly higher rates in these recent years when hydro was below average.

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. 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. PGE's HGA is designed to isolate hydro generation and market prices from all other factors, therefore, it is useful to see what happens when those two variables are isolated in MONET.

We did this comparison. CUB Exhibits 104 and 105 are the MONET runs PGE filed in UE 115 and UE 139 projecting power costs for 2002 and 2003. 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. In addition to this, we also calculated what PGE's HGA would have charged customers for those years in order to compare what low hydro costs the Company to what the Company would charge customers for the lost hydro.

We looked at the following to make the comparison:

- *Projected Power Costs from MONET* – This data is from the original MONET runs that established power costs for the UE 115 and UE 139. CUB Exhibits 104 and 105.
- *Power Costs Adjusted for Actual Hydro & Market Prices* – This data is from MONET runs using all of the original data except hydro generation and market prices which were updated with the actual data. This represents how PGE would have dispatched its system in a scenario with the projected variables and the actual hydro generation and market prices. In keeping with PGE's proposed HGA, it allows us to isolate hydro and the associated market prices. CUB Exhibits 106 and 107.
- *The Cost of Low Hydro* – This represents what the low hydro actually cost PGE, given that PGE would dispatch its other resources differently under the above two scenarios.
- *PGE's HGA Charge* – This is an approximation of what PGE's HGA mechanism would have charged customers for the lost hydro. Please see CUB Exhibit 108.
- *Overcharge* – This is the amount PGE would have charged customers BEYOND what it actually would have cost them to replace the power lost due to low hydro.

BEGIN CONFIDENTIAL MATERIAL

END CONFIDENTIAL MATERIAL

It should be noted that CUB is not alone in believing that low hydro production can be partially offset by increased thermal production. PacifiCorp recently filed a request to "defer its increased power costs caused by continuation of a multiple-year trend of low hydro generation. PacifiCorp proposes to calculate its increased costs by comparing its actual hydro generation with that reflected in rates and quantifying the costs of replacement market purchases *and increased thermal generation.*" Emphasis added, PacifiCorp Notice of Application, February 1, 2005.

In 2003, PGE filed a deferred accounting application due to hydro conditions. That deferral included all changes in net variable power costs, not just the effects of low hydro. PGE claimed that for the entire year, it incurred $31.6 million in excess net variable power costs, and proposed that $26 million of that be charged to customers. OPUC Order 04-108. The HGA mechanism they are now proposing would have charged customers over $55 million for low hydro in 2003, more than twice what the Company requested at the time. CUB Exhibit 108. In a poor water year the HGA will overcharge customers.

B. PGE's HGA Is Inconsistent With Its Own Least Cost Plan

In PGE's recent Least Cost Plan, the Company included some discussion of the issue of hydro variability. The Company said that it "evaluated the economics of holding a 'long' energy position as a hedge against low hydro conditions." It notes that "Idaho Power and the Idaho Public Utilities Commission found that planning to a 70 percent hydro standard was a cost-effective hedge against hydro conditions." CUB Exhibit 109 is an excerpt from PGE's LC 33 Final Action Plan, 2002 IRP, addressing the Company's "Hydro Planning Standard."

Ultimately, in its Least Cost Plan, PGE proposes to do the following:

> If it appears that the WECC energy and capacity reserves are shrinking, we may propose to acquire, and include in the annual reset of net variable power costs, the cost of option premiums to hedge the price risk of below average water condition. On an expected cost basis over time, this approach is likely to cost less than other options and also has a lower risk of causing price volatility.
>
> We will use any CCCT duct firing capability we have available during poor water conditions, if required, and any other time that is economic to do so. This means duct firing serves a dual purpose. It can be used during low hydrogeneration conditions and to meet winter peaks. In either case, we would use it when a more economic alternative is unavailable.

CUB Exhibit 109

Unfortunately, PGE's proposed HGA mechanism is not compatible with these guidelines. Customers pay the fixed costs – the premiums – for the hedges, as well as the fixed costs associated with duct firing, but, under PGE's proposed Hydro Generation Adjustment, customers would be charged as though all lost hydro were being replaced by market power, and would never receive any value for the hedges and duct firing. PGE's own Least Cost Plan contains strategies to reduce the need to purchase power to replace lost hydro, but PGE's HGA ignores this strategy to reduce costs, and charges customers more than the actual cost of replacing lost hydro.

C. $2.5 Million Dead-Band And $0 Sharing-Band Is Ridiculous

It is not clear to us why PGE proposed a $2.5 million dead-band and no sharing of costs beyond the dead-band. After several years of discussion, they must recognize that such a proposal is a non-starter for other parties. PGE cites the history of PCAs in Oregon and the existence of PCAs for other utilities in the region. In looking at those PCAs, however, it is immediately clear that they do not set a precedent for a mechanism as generous to a utility as what PGE is proposing. After several years of talking about the risk associated with hydro variability, we are disappointed with PGE's proposal. Rather than offering a mechanism to bridge the gap between the parties, PGE has staked an extreme position.

i. Oregon Precedent Does Not Support Such A Generous Mechanism

The most recent case that addressed hydro variability was UM 1071, PGE's 2003 hydro deferral. In that docket, PGE proposed a 95/5 sharing mechanism, where 95% of the costs of changes in Net Variable Power Costs (NVPC) would fall on customers. Order 04-108. In addition, the time lag between the beginning of the year, and the date upon which PGE actually filed the mechanism would act as a dead-band. According to the Commission Order 04-108, PGE's proposal would require the Company to absorb 18% of its excess Net Variable Power Costs for 2003. Yet the Commission rejected the Company's filing, and instead suggested that the, "parties might present a PCA proposal similar to the one Staff outlined here." Order No. 04-108. Staff's proposal was for a PCA that protected the Company from extreme events only.

PGE argues that it has had a PCA at various times in the past, and that such a mechanism is not out of the ordinary in Oregon regulation. What they did not say, is that those PCAs were not nearly as generous as what they are proposing now. CUB Exhibit 110 is the Company's answer to CUB Data Request 11 which shows the PCA history that PGE cites. It shows that the Company's PCAs over the last 20 years have had sharing mechanisms with the utility typically absorbing 20% to 50% of the cost associated with the PCA. The two most recent PCAs had tiered sharing-bands, where the utility paid 50% of the costs until they reached a certain level, and then customers absorbed a greater share. In addition, these two PCAs had dead-bands where the utility was required to absorb the first $28 to $35 million in higher costs. CUB does not believe that this history supports a mechanism with no sharing and a dead-band of just $2.5 million.

ii. Regional Precedent Does Not Support PGE's Proposal

PGE also cites other utilities in the region, but again, a review of PCAs for those utilities does not show a lot of precedent for the mechanism PGE is proposing. It should be noted that while the other utilities' have PCAs that apply beyond hydro to all power costs, none of these utilities have PGE's RVM mechanism. PGE's RVM is a unique mechanism in the region which updates the Company's power costs each year, thereby removing much of the Company's risk associated with changing fuel, load, and other non-hydro costs.

CUB Exhibit 111 summarizes the other PCA mechanisms in the region. PGE's current proposal stands out as the only one that has no sharing-band, placing 100% of the costs beyond the dead-band onto customers. In addition, the examples from Washington, Avista and PSE, have dead-bands that are considerably more significant that what PGE is proposing. As a percent of revenue, the dead-bands in Washington are more than 10 times greater than what PGE is proposing here.

D. $20 Million Account Build-Up Is A Red Herring

PGE's proposed mechanism includes a Hydro Generation Balancing Account (HGBA). The excess or lost hydro for the year, net of PGE's dead-band, is added to the HGBA. We have already discussed how the additions to this account will be over-generous in bad hydro years, and under-generous in good hydro years, so one can safely presume that the HGBA will be heavily weighted in the Company's favor.

In an attempt, perhaps, to distract the Commission from the meager dead-band, PGE's mechanism assures us that customers will not be charged (or credited, should it actually come to that) until the HGBA reaches +/- $20 million. This, however, is not an annual number (i.e. a dead-band), and it is part of the balance customers owe PGE. For example if the HGBA is at $19 million, it doesn't mean that customers don't owe PGE the money. The $19 million is in an account, earning interest, waiting to grow another million and be charged to customers. This $20 million band only effects <u>when</u> the balance is paid, it does not affect the amount that customers ultimately pay.

E. PGE's HGA Mechanism Has No Analytical Support

While describing their mechanism as "straightforward and transparent" (PGE/700/Kuns/2), PGE simultaneously makes no attempt to demonstrate that it reaches a fair outcome or is consistent with PGE's management of hydro variability. In fact, PGE provided no examples in its testimony of how its proposed HGA mechanism might actually work … we had to do that.

Instead, the Company only provided testimony from Mr. Kuns that shows how the math might work, but makes no attempt to show the real effects of the mechanism under actual conditions. Mr. Kuns begins by simplifying market prices, and keeping them fixed despite his own statement that, all else being equal, market prices generally go up when hydro is scarce and down when hydro is plentiful. PGE/700/Kuns/9. He also chose to ignore on- and off-peak pricing, and monthly compounding of interest.

Mr. Kuns chose to use $41/MWh, a more-current market price, with historical data, because, “most of the early to mid-1990’s, spot market transactions could be made for between 10 and 30 mills/kWh. Such prices are not consistent with today’s market prices or expectations of market prices for the foreseeable future.” PGE/700/Kuns/9. Yet he also states, “the purpose of the example is illustrative, not predictive of future events such as hydro output or corresponding market prices.” PGE/700/Kuns/10. So which is it, an example with projected future data or an example with actual past data?

Unfortunately, it is neither. Not only is PGE’s example so watered-down as to be meaningless, it is also, unfortunately, quite misleading. Despite his disclaimers about the example’s simplifying assumptions, he never the less makes the reassuring conclusion that:

> Since the tariff mechanism requires a three-year amortization period of any balance in excess of $20 million, any resulting rate charges or credits are likely to be small in a given year.

PGE/700/Kuns/8

CUB Exhibit 108 shows what the result of PGE mechanism would be in 2002, 2003, and 2004. We compared projected and actual monthly hydro output, and used actual monthly on- and off-peak market prices. Rest assured, the resulting rate charges are not small. As partially presented in Table 1, PGE’s HGA would have charged customers approximately $9.8 million in 2003, $25.8 million in 2004, and $45 million in 2005. On top of this, customers would owe an additional $135 million to the Company.

F. PGE's ROE Claims Are Largely Irrelevant

PGE spends little time offering analysis of their proposal and a great deal of time talking about ROE, climate change, hydro modeling, and other issues. We don't agree with much of what PGE argues, but it really doesn't matter, because even if one were to accept all of PGE's claims, they simply support the conclusion that there should be some mechanism in place to allocate the risk of hydro variability. The testimony offers little support for PGE's proposed mechanism.

In UM 1071, the Commission recommended a PCA to deal with hydro variability:

> We are aware of climate change and other factors, such as hydro availability, that may affect PGE's ability to recover its hydro losses. Therefore, although we do not find that this case is appropriate for deferred accounting, we encourage the parties to this docket or other interested persons to present alternatives to deal with hydro variability. For instance, parties might present a PCA proposal similar to the one Staff has outlined here. For the reasons that Staff provides, and that CUB has cited as well, we believe a PCA may be an appropriate way of permanently allocating risks and benefits of hydro variability between shareholders and ratepayers.

Order 04-108, page 10-11

That is the direction from the Commission that we take into this docket. For this reason, we don't need to spend much time debating the arguments they offer concerning cost of capital and other issues. Our focus is on whether the mechanism they are proposing is a reasonable one, and, regardless of whether their testimony over the need for a PCA is credible, their solution is not a reasonable one.

III. We Agree There Is A Problem, But It Is A Different One

PGE believes there is a big problem associated with the variability of hydro and the problem, as PGE sees it, is that the Company should not have to bear the risk of changes in power costs due to changes in hydro conditions. Their solution is to shift nearly all the risk – or, according to our analysis, more than all the risk – to customers.

A. Hydro Variability & Climate Change

We agree with PGE that there are problems associated with hydro variability. We think, however, the problems are different from what PGE presents. The problems we think that needs to be addressed are: 1) how to address hydro variability in the least-cost manner, and 2) how to address the climate change issues that are affecting hydro. We are not convinced that current practice is designed to do either of these.

The current approach, which is internalized in the RVM process, is to try to minimize overall power costs when average hydro conditions are present and, based on the Company's Least Cost Plan, add hedges and gas generation to reduce the cost of replacing low hydro. The focus in the Least Cost Planning process is to reduce the risk associated with bad hydro conditions for the Company. An approach that places the fixed costs of hedges and gas-fired facilities in rates is a good solution for the Company. Customers pay for the ongoing costs of these resources, but receive none of the benefits. Of course, there is an additional benefit for PGE: if market prices increase relative to gas prices for any reason, not just low hydro, these resources become economic, and the Company can sell or use them, but the revenue from these transactions flow to PGE shareholders, not to the customers who paid the fixed costs.

When examining power costs, we ought to try to identify what will produce the least-cost approach over the widest possible range of hydro conditions, not simply which strategy will reduce the risk to the Company in bad water years. PGE dismisses the Idaho Power approach of planning for 70% of average water. CUB Exhibit 109. If the Company were to attempt to balance its load and resources assuming 90% (or 80%) of average hydro and therefore create a long position, in a good hydro year, the Company would find it necessary to resell some of its purchased power for less than its purchase price, but this would be offset by the value of additional power sales from selling the excess hydro power. In a bad hydro year, the Company would have less need to turn to the market for replacement power.

Staff has advocated stochastic modeling to help us identify annual power costs. CUB has not developed a position on whether this would be an improvement in setting power costs. We do believe, however, that such modeling would provide the analytical tools necessary to determine the least-cost approach to hydro variability. With such modeling, we can compare the various strategies, and identify which strategy has the lowest cost under the widest range of possible hydro condition, good, bad, or average.

B. Does PGE Agree With Its Expert Witness Or Not?

Frankly, we not sure what to make of PGE's testimony as to the root of the hydro-variability problem. Their expert witness, Dr. Philip Mote testifies that historical records are not adequate to forecast hydro production in the future because:

> Owing to human activities, the atmospheric concentrations of dozens of greenhouse gases are increasing at a rate far exceeding any in the last 10,000 years. Carbon dioxide has increased by some 33% since 1800; methane, over 150%; and there are many gases that are solely man-made. These greenhouse gases increase the heat-trapping

> capacity of the atmosphere and are almost certainly the cause of the increase in Earth's average temperature during the last 50 years.

PGE/400/Mote/4

In its first breath, absolving itself of any responsibility to address the global warming which is affecting its hydro resources, the Company undercuts Dr. Mote's conclusion by stating:

> Dr. Mote states his belief that human causes are a significant factor in the warming trend he observes. PGE is still reviewing the scientific evidence and has not adopted a policy position on this issue yet.

PGE/100/Lesh/19

Dr. Mote testifies that forecasting hydro is a problem because of climate change caused by human activity, and PGE says they don't know if humans are causing climate change. This places Dr. Mote's testimony in a sort of orphan position, as the party that sponsored the testimony doesn't support it. PGE may not wish to adopt the conclusions of its expert witness, CUB, however, is more than happy to adopt Dr. Mote's conclusions.

A more fundamental question, however, is not who believes PGE's witness, but what is being done about climate change and its affects on PGE. While Dr. Mote was hired to discuss climate change and its affect on forecasting hydro, it is likely that he also has interesting things to say about the effect climate change might have on the operation of PGE's coal-fired plants, and how climate change might affect the Company's summer and winter peak loads. There is little doubt that climate change will have a real and significant impact on electricity demand and electric generation in the Pacific Northwest. We ought to be addressing this broader climate change problem.

IV. CUB Recommendations

In 2002, PGE proposed a PCA. In our testimony in August of that year CUB proposed a set of principles that we suggested the Commission should use as a guide in considering a PCA. Those principles are reprinted below.

Unfortunately, 2 ½ years later, we have made little progress. PGE's proposal in this docket is a step backwards in the ongoing discussions over what to do about hydro variability, and CUB is once again left with the dilemma of what to recommend to the Commission, beyond outright rejection of PGE's proposal.

Under the current docket's schedule, CUB does not get a second chance to submit testimony, and, at this point, the only proposal on the table is from PGE. We expect that Staff will propose an alternative mechanism, as may other parties, and PGE may well propose something new in its rebuttal. As of today, however, there is only one proposal on the table for us to critique, and it is clear that the Commission should reject it.

CUB has decided not to propose an alternative mechanism. Under the current schedule, any proposal we make will not be vetted in testimony by Staff or the other parties. We have doubts whether the best way to design such an on-going mechanism is for each party to submit a different proposal. This might get us a mechanism, it might even get us a mechanism that CUB designs, but we are not convinced it will get us the best mechanism.

Instead, as in 2002, CUB has decided to set out a list of principles that should be incorporated into any hydro adjustment mechanism or PCA, as well as a few recommended actions that the Commission should take.

A. Recommended Principals

In 2002, we recommended the following:

<u>2002 CUB Principles For A Hydro PCA</u>

Principle 1. PGE has the highest rates of any major utility in the region. A PCA for PGE should not unnecessarily add to PGE rates. A PCA should only add to PGE's costs in extreme circumstances. It should not be triggered except in rare circumstances where power costs are well beyond the normal range.

Principle 2. PGE has the highest rates of any major utility in the region. A PCA should facilitate passing on lower power costs to customers. Customers have little ability to initiate a rate case as the PGE's cost decline, so theoretically a PCA could be a tool to ensure that lower power costs are passed through to customers. While these first two principles seem contradictory, they are not. They simply recognize that the sharing and dead-band do not have to be symmetrical. Utility regulation is not symmetrical.

Principle 3: The PCA should not have a lost revenue recovery mechanism. Customers should not have to pay a surcharge through a PCA to make up for the revenue the Company loses because customers cut back due to unaffordable electric rates after a big increase.

Principle 4: The PCA should not allow any higher costs caused by the FERC investigation of PGE or subsequent penalties to be passed through to PGE customers. As we said, we do not know how the Commission accomplishes this if a PCA is continued, but it is necessary.

Principle 5: The PCA balance should be placed in a deferred account rather than be subject to an automatic adjustment clause. The deferral statute has three important pieces that are missing from an automatic adjustment clause. First, deferrals are subject to prudence reviews. Second, a deferral is subject to an earnings review. Finally, the deferral statue limits recovery to 6% of the utility's overall revenues.

CUB still believes that these 2002 principles are valid and provide useful guidelines in designing an adjustment mechanism, but it is worth updating them and placing them in the current context.

i. A PCA Should Be For Costs Outside Of The Normal Range

PGE is still one of the most expensive utilities in the region. Adding costs unnecessarily to PGE's rates is as much of a concern now as it was in 2002. Echoing our testimony about deferrals in UM 1147, a PCA mechanism should be triggered only in rare circumstances when power costs are well outside the range of variability traditionally accepted by companies and customers alike.

ii. A PCA Should Be Asymmetrical

A PCA or hydro-only PCA should have wide dead- and sharing-bands, and should be asymmetrical. Recent history in Oregon suggests several sharing-band allocations (50-50;75-25, 90-10). Regardless of the actual numbers, these sharing-band allocations should not be symmetric. There is a great deal of variability to hydro production. Hydro conditions outside of a normal range, which is included in the expected risk traditionally born by utilities, can be shared with customers, but this requires a significant dead-band. In exchange for customers accepting that risk and helping the company manage the risk, customers should also receive a share of the benefits of excess hydro. Even PGE acknowledges that the risks and costs associated with low hydro are greater than the benefits associated with good hydro, PGE/100/Lesh/10, and therefore, the dead-band and/or sharing-band allocations must be asymmetric to reflect the asymmetric market values of excess hydro and scarce hydro. The dead-band should be narrower on the customer benefit side and/or the sharing-band allocations more generous.

iii. A PCA Should Be Narrowly Defined In Scope

A PCA or hydro-only PCA should be as limited as possible. In 2002, we argued against including lost revenues in a PCA. Today, 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 – though we would argue that a better way to calculate the cost of lost hydro is to run MONET adjusted for actual hydro and market prices. A hydro-only PCA doesn't have to ignore the flexibility provided by a company's thermal generation, hedges, and other resources.

PGE's RVM offers the Company the ability to update fuel prices, loads, and contract prices annually, so the Company has less risk in these areas, and has not convinced us that there is a need for an ongoing PCA to cover these factors. The more narrow the scope of a PCA, the less likely the PCA is to have unintended consequences.

iv. A PCA Should Hold Management Accountable

A PCA should neither reward nor protect poor management. In 2002 we were concerned about the ability of a PCA to pass costs associated with improper wholesale trading practices through to customers. Today, we are concerned that a PCA could remove a company's incentive to contain power costs in poor hydro conditions, and even encourage PGE to depart from its Least Cost Plan's strategy for dealing with poor hydro.

v. A PCA Should Include Customer Protections

A PCA should include some of the protections associated with deferrals. In 2002 we recommended that PCA balances should be placed in deferred accounts so customer protections associated with deferrals, which are missing from automatic adjustment clauses can be applied. Whether a deferral is used or not, we believe that a PCA should explicitly contain the protections we have been concerned about:

<u>A Prudence Review</u>. In terms of low hydro, there must be the ability to review how a utility manages its response to low hydro to ensure that the management is acting prudently before costs associated with low hydro are put into rates.

<u>An Earnings Review</u>. A utility should not be able to recover additional costs from customers if its rates are already high enough to cover those costs. This is the principle behind an earnings review. If a company is earning its authorized rate of return or above, then there is no need to raise rates to cover low hydro. The need for an earnings review is reduced by a wide dead-band. A substantial dead-band essentially ensures that costs are great enough to affect earnings before such costs can be place into rates. However, even in those circumstances an earnings review does no harm.

<u>A Cap On Amortization</u>. Currently amortization of deferrals is limited to 6% of rates. This is important. When we amortize the costs associated with a PCA, customers are no longer paying the current cost of service, but are paying for a previous year's cost of service. Such amortization should be limited so as to not place undue hardship on customers.

<u>Appropriate Amortization Time-Period</u>. In addition, the risk of a 1-in-10 bad hydro year is 1-in-10 years. If you were to spread the amortization of a 1-in-10 hydro event out over 10 years, customers would be fairly and equally paying for the risk of poor hydro. In reality, we do not want to fix it so tightly, because it is possible to have a 1-in-10 year hydro event twice in four years, but it is a reasonable regulatory policy to spread the amortization of such an event out over a number of years.

B. Recommended Actions

In addition to the above principles, we have the following recommendations:

i. Deny PGE's proposed HGA

Though this conclusion speaks for itself, we would like to point out one more time that PGE's proposed HGA mechanism is so far beyond reasonable or rational that it does not even deserve consideration.

ii. Do Not Make This Order Retroactive

PGE filed a deferral application earlier this year in order to make the Commission decision in this docket retroactive to January 2005. We believe that it is bad public policy to apply a Commission decision in this docket back to the beginning of the year. If the Commission decides to implement a hydro-only PCA, the Commission should evaluate the testimony and decide what would be fair on a going-forward basis; independent of any known impact on rates. To apply the mechanism retroactively to cover a year with poor hydro changes the Commission decision. The order would no longer solely concern what is a fair allocation of risk going forward, but would also contain retroactive ratemaking, a tool typically reserved for extreme circumstances.

PGE filed a deferred accounting application for the current year to deal with poor hydro. That docket should be handled separately. The Commission decision in that docket may be influenced by what the Commission thinks is the appropriate policy for an on-going, hydro-only PCA, but it still should remain a separate decision, in a separate docket.

iii. Issue A Draft Order

The Commission should consider issuing a draft order in this docket if no settlement is reached. We assume that the Commission will not adopt PGE's mechanism, but the Commission's choices are to reject PGE's proposal outright and implement no mechanism, or to implement a proposal that has not been fully reviewed by the parties. This could be whatever Staff proposes, what PGE proposes on rebuttal, or something the Commission itself develops. Approving a draft order, would allow the Commission to do this, but would also allow parties to review the Commission's proposal and recommend changes to that proposal.

iv. Conduct An Investigation Into The Least-Cost Approach

The PUC should conduct an investigation into the least-risk, least-cost approach to hydro variability. This should be done independent of the utilities' Least Cost Plans. Least Cost Plans inevitably are focused on the next resource(s) needed to serve load assuming normal weather and hydro conditions. This decision swamps the consideration of what happens outside of normal hydro conditions. PGE's LCP says that Idaho Power's approach of planning for less-than-average hydro is not the best, and that hedges are a better approach. CUB Exhibit 109. We are not convinced what the best approach is, and are not even sure what approach each utility is actually using. We do believe that simply focusing on who pays the costs is not the proper regulatory response. We need to be asking what the best approach is to minimize the cost of hydro variability.

v. Consider Demand Response

Part of the strategy to deal with low hydro should involve customers. The PUC should consider guidelines for when demand response programs are triggered during serious low hydro events. When market prices spike, demand response programs focused on immediate results may become cost-effective. This can include simply asking customers to reduce their usage. During the energy crisis of 2000-2001, a 1-in-50 event, customer response programs targeting all classes of customers were implemented. Customers were encouraged to conserve energy. These programs worked; customers did cut back.

When thinking about low hydro, we should think about when we ask for customer participation. A proposal such as PGE's hydro tariff is asking customers to pay higher rates for power, but customers will not see it on their bill until next year, well after they have used the power. What is the expectation for letting customers know that usage today will cause higher rates tomorrow? What programs can be implemented, so customers have the option of reducing their usage today to help avoid higher rates in the future?

vi. Require The Utility To Address Climate Change In Its Least Cost Plan

Utilities should further explore climate change, both as climate change impacts their systems and as their systems impact climate change. Climate change is not a narrow issue of hydro variability; it also impacts a utility's ability to use its other generating resources, especially its thermal resources, as well as impacting a utility's loads, most-notably summer peak.

V. Conclusion

In closing, CUB is not opposed to examining the issue of hydro variability, but it should be done carefully and thoughtfully, as we will likely live with the results of our efforts for a long time. PGE's proposed HGA mechanism should be rejected outright.

CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of February, 2005, I served the foregoing Opening Testimony of the Citizens' Utility Board of Oregon in docket UE 165 upon each party listed below, by emailing a non-confidential version, and mailing a confidential version to the appropriate parties through the U.S. mail, postage prepaid, and upon the Commission by emailing a non-confidential version and hand-delivering 5 confidential copies to the Commission's Salem offices.

Respectfully submitted,

Jason Eisdorfer #92292
Attorney for Citizens' Utility Board of Oregon

J JEFFREY DUDLEY -- **CONFIDENTIAL**
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST 1WTC1300
PORTLAND OR 97204

RANDALL J FALKENBERG -- **CONFIDENTIAL**
RFI CONSULTING INC
PMB 362
8351 ROSWELL RD
ATLANTA GA 30350

MAURY GALBRAITH -- **CONFIDENTIAL**
PUBLIC UTILITY COMMISSION
PO BOX 2148
SALEM OR 97308-2148

PATRICK G HAGER -- **CONFIDENTIAL**
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204

DAVID HATTON -- **CONFIDENTIAL**
DEPARTMENT OF JUSTICE
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096

S BRADLEY VAN CLEVE -- **CONFIDENTIAL**
DAVISON VAN CLEVE PC
333 SW TAYLOR STE 400
PORTLAND OR 97204

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 308
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem Oregon

PREVIOUS EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UG 152, UM 995, UM 1050, UM 1071, and UM 1121. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

WITNESS QUALIFICATION STATEMENT

NAME: Lowrey R. Brown

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Utility Analyst

ADDRESS: 610 SW Broadway, Suite 308
Portland, OR 97205

EDUCATION: Master of Science, Engineering
Bachelor of Science, Civil Engineering
Stanford University, Stanford California

PREVIOUS EXPERIENCE: Provided comments and participated in settlement discussions in OPUC dockets UE 161, UM 1014, UM 1147, UM 1158, and UM 1169. Presented testimony and engaged in settlement proceedings in UM 1121. Participated in technical subcommittees for the Governor's Advisory Group on Global Warming, and in the Regional Representatives Group for Grid West. Currently involved in the development of PacifiCorp and NW Natural's Integrated Resource Plans.

Prior to this, worked as a consultant with KEMA-Xenergy in Portland from 2002 to 2003 on energy and energy efficiency issues. Between 1997 and 2001, freelanced in Colorado for The Valley Journal, Solar Energy International, Energy Systems Engineering, and Resource Engineering providing writing and technical assistance.

Annual Production of PGE Generation (MWh)
CUB DR-010 Attachment 10-A

	1995	1996	1997	1998	1999	2000
Resources						
Round Butte	951,640	1,150,286	1,274,086	1,133,384	1,196,587	1,074,301
Pelton	414,246	504,481	552,907	488,457	516,856	466,352
Oak Grove	276,233	292,928	285,084	270,897	295,019	260,848
North Fork	228,633	252,771	231,357	212,492	245,493	192,985
Faraday	195,429	182,008	200,642	182,337	210,980	168,392
River Mill	105,468	117,864	120,136	112,861	130,041	105,081
Bull Run	134,493	89,473	116,142	109,121	102,712	101,610
Sullivan	128,018	112,187	118,141	127,429	119,851	128,951
Portland Hydro Project	98,521	109,429	106,020	89,074	94,254	77,847
Wells *	831,681	1,121,238	1,049,014	799,986	959,887	809,891
Rocky Reach *	698,979	920,719	913,992	717,026	892,376	750,343
Wanapum *	827,200	1,038,739	1,053,635	811,495	977,409	769,572
Priest Rapids *	666,351	781,183	738,899	584,899	707,062	625,390
Total Hydro	5,556,892	6,673,306	6,760,055	5,639,458	6,448,527	5,531,563
Boardman	1,051,547	1,169,842	1,014,292	2,268,760	2,492,054	2,283,660
Centralia	113,748	176,393	206,896	228,084	216,087	
Colstrip	1,767,564	1,311,002	1,934,856	2,230,437	2,217,047	1,964,872
Total Coal	2,932,859	2,657,237	3,156,044	4,727,281	4,925,188	4,248,532
Beaver	2,081,599	813,743	566,897	1,772,979	1,446,490	2,837,242
Bethel	3,715	13,693	396	39,810		
Coyote Springs	186,787	1,036,806	704,246	1,678,368	1,308,507	1,817,243
Total Gas	2,272,101	1,864,242	1,271,539	3,491,157	2,754,997	4,654,485
Total Production	10,761,852	11,194,785	11,187,638	13,857,896	14,128,712	14,434,580

Source: for years 1995-2003, Ferc Form 1, pages 402-406, line 12 for PGE owned generating plant, Ferc Form 1, pages 326-327, column g for LT hydro contracts.

Notes: * Includes allocation to Canadian Entitlement and Fish Spill Replacement re: Pacific Northwest Coordination Agreement Canadian Entitlement

Excerpt From PGE's Final Action Plan March 2004, pages 32-34.

What Is Our Hydro Planning Standard?

For what we call "run-of-the-river" hydro resources, capacity and energy are about the same. While we can increase production for a given hour by a small amount, the ability to do this is limited by actual stream flows.

For hydro resources with storage, however, planning is more complex. The average energy the plant can produce is a result of precipitation and storage. Using stored water, operators can produce nameplate capacity during any given hour. Using the stored water, however, is likely to affect the average energy the plant can produce, particularly if the capacity need extends beyond an hour, which can occur during peak needs caused by extreme cold weather. Cold and dry conditions exacerbate this. At some point, the extent to which we rely on these hydro resources for capacity affects the extent to which we can rely on them for energy under average water conditions.

Moreover, all hydrogeneration – run-of-the-river or storage-based – faces the constraint of precipitation. Less than average precipitation affects the energy available to a large number of utilities in the Northwest, directly or indirectly through contracts including those with BPA. Under poor water conditions, all of these utilities will need to find resources to provide electricity required by their customers.

While there is transmission available to bring in the needed energy from a wide variety of sources throughout the WECC, it is likely that electricity purchased under such conditions will come from resources that produce electricity at a higher cost. That is because resources producing at a lower cost will be under long-term commitment to other retail load, and because sellers will expect buyers to accept higher prices, given the shortage conditions.

Under an extreme water-driven energy shortage, depending on the amount of excess energy production capability in the region, it is possible that electricity would not be available at any price, threatening reliability.

This is a significant planning and ratemaking issue for us, given that we currently rely on PGE-owned and contract hydro resources, under normal water conditions, for approximately 26 percent of our customers' current energy needs and 37 percent of our customers' current capacity needs.

In the *Supplement*, we proposed to plan for *poor* hydro conditions by acquiring additional long-term supply. We promised to further evaluate the economics of this proposal in this *Final Action Plan*. We are now proposing to plan to *average* hydro conditions, but intend to take certain resource actions in the event of tight supplies in the region.

We evaluated the economics of holding a "long" energy position as a hedge against low hydro conditions. For a modest but ongoing annual fixed cost increase, a hydro hedge could reduce replacement cost volatility by capping the replacement cost for the lost hydro generation At the same time, this long energy position displaces winter peaking capacity that we otherwise would need to acquire, thus avoiding the associated capacity charge. Our analysis suggests that, over time, this approach could be more economic than separately acquiring winter peaking capacity and summer energy for poor hydro years. Being able to cap the cost for replacement energy also moderately reduces market price risk.[4]

However, planning for lower than average hydro conditions is only a partial hedge for hydro variances. It provides a natural hedge against price excursions, but cannot provide protection for the large replacement cost of low-cost hydrogeneration *versus* the fuel cost of even a 7,000 heat rate CCCT. The bulk of the cost exposure cannot be hedged by maintaining a long energy position, and a power cost adjustment is still required.

Low hydro conditions can be hedged with either a low heat rate CCCT, or with a resource that has a higher heat rate but a lower capital cost, such as duct firing or an SCCT. Because the fully-allocated cost of incremental duct firing for the assumed number of operating hours is less than the related, fully-allocated cost of a base-load CCCT, it is more economic than acquiring additional base-load CCCT.

We cannot be certain about how a resource may subsequently compare to the market, so another way to mitigate poor hydro is to look about 18 months ahead at the region's resources. If the regional load-resource balance looks like it will be tight, we may propose to acquire options on short-term resources ahead of the spot market, in advance of *any* knowledge of what the water year may bring. This would provide a limited hedge in a way similar to the scenario described above.

From a planning perspective, we propose the following guidelines:

- If it appears that the WECC energy and capacity reserves are shrinking, we may propose to acquire, and include in the annual reset of net variable power costs, the cost of option premiums to hedge the price risk of below average water conditions. On an expected cost basis over time, this approach is likely to cost less than other options and also has a lower risk of causing price volatility.

- We will use any CCCT duct firing capability we have available during poor water conditions, if required, and any other time that it is economic to do so. That means duct firing serves a dual purpose. It can be used during low hydrogeneration conditions and to meet winter peaks. In either case, we would use it when a more economic alternative is unavailable.

For ratemaking purposes, we are seeking outside of this resource planning process a better way to reflect the variability of hydro production in the rates our customers pay.

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[4] Idaho Power and the Idaho Public Utilities Commission found that planning to a 70 percent hydro standard was a cost-effective hedge against hydro conditions.

Exhibit 110, CUB Data Request 11: PCA History in Oregon

Tariff Schedule	OR. No.	PUC Order No.	Docket	Date Order Effective	Time Period PCA Cost Incurred	Deadband	Sharing Percentage PGE & Cust.	Notes:
100	E-6	74-657	UF-3091	9/1/1974	9/1/74 - 2/28/75	$0.00	N/A	2 mill flat charge for each kWh delivered to recover any power cost in excess of 4.8 mills per kwh. Staff estimates recover of $14.6 million as of 3/75
		75-005		12/31/1974		$0.00	N/A	Reduce PCA to 1 mill per kWh on all bilings made on and after 1/6/75
		75-089		1/30/1975		$0.00	N/A	In light of the mild winter weather and continued conservation, eliminate 1 mill assessment on all billings made on and after 2/4/75.
	E-7	75-832	UF-3157	9/26/1975	No PCA In Affect			PCA request for 1974-1975 winter season is not approved
		77-456	UF-3339	7/7/1977	No PCA In Affect			Emergency Rate Increase of 18.5% denied. PGE to file proposed tariff with variable millage surcharge to recoup power costs in excess of those expected to be experienced under median water conditions.
100	E-8	77-559	UF-3339	8/19/1977	9/1/77-6/30/78	$0.00	N/A	2.2 mills per kWh to be effective with service rendered on and after 9/1/77.
		77-813	UF-3339	11/30/1977		$0.00		Surcharge collections for Sep and Oct was $2,360,801. Excess Power costs for this period were $1,115,694. Surcharge exceeded excess power costs by $1,245,107. Estimated Nov excess power cost at $920,000 and $2,100,000 revenue from the surcharge. By Nov surcharge revenues could exceed excess power costs by $2,425,107. Staff anticipates excess power costs for Dec and January of approx. $2,000,000. Therefore, the surcharge collection will suspend effective for service rendered on and after 12/1/77.
		78-069	UF3339	2/3/1978		$0.00		Temporary surcharge suspension be continued in effect pending submission of the company's Jan through Jun 78, results of operations and audit of those results by the Commissioner's staff. Surcharge revenue overcollection at 12/31/77 of $2,062,175.79, net of income tax effects, be placed in reserve pending further order of disposition by the Commissioner.
		78-732	UF3466	10/1/1978		$0.00		Commissioner could not find that an emergency exists which justifies a surcharge in PGE rates (Trojan plant shut down by NRC)
		79-075	UF-3339	1/31/1979		$0.00		Under Order No. 78-069 an audit was conducted of PGE's results of operation from 9/1/77 through 6/30/78. The Commissioner ordered no collection of undercollected amounts nor refund of overcollected amounts. Reserve amount of $2,062,175.79 net of income tax effects be released.
100	E-10	79-830	UF-3518	11/15/1979	Qrtly beginning 11/14/79 thru 9/87	$0.00	80% of increased cost to Cust and 80% of benefit if cost below base rate to Cust.	Surcharge shall not exceed .40 cents per kWh. No charge shall be made when the Adjustment Rate is less than .05 cents per kWh
	E-11 thru E-14	80-021	UF-3518	1/14/1980		$0.00		Amend Order No. 79-830 to reflect corrected Base Power Rates and wording on Appendix page 3 and 4
		87-1017	UE 47, 49	9/3/1987				Order ceased current Power Cost Adjustment
105	E-15 & E-16	91-1781	UM-445	12/20/1991	11/1/91 - 3/31/92	$0.00	See Notes	Defer 90%, for later ratemaking treatment, certain incremental replacement power costs associated with an outage at the Trojan Nuclear Plant
		91-1781	UE-82	12/20/1991		$0.00	See Notes	Amortize deferral amts beginning 1/1/92, no more than 80% of replacement power costs deferred for the month of Nov. 1991, during the month of January 1992, with ongoing amortization of deferrals. Rate change on an annualized basis shall not exceed 3% of PGE's revenue for the preceeding calendar year.
		91-1715	UE-81					Temporary price increase through a replacement PCA - SUSPENDED. Order 91-1781 Permanently Suspended UE-81
		93-309	UM-529	3/11/1993	12/4/92 - 3/31/93	$0.00	See Notes	Defer 80% of incremental replacement power costs resulting from the outage of Trojan
		93-1493	UM-594 UM571	10/15/1993	7/1/93 - 3/31/94	$0.00	See Notes	Defer 50% of excess Trojan replacement power costs in the amount of approx $53 mill
126	E-17	01-231	UM-1008 UM-1009	3/14/2001	1/01 - 9/01	+/- $35 million	Tiered	100% deferral of net variable costs from the baseline net variable power costs of $176 million
127	E-17	01-777	UE-143	8/31/2001	10/01 - 12/02	+/- $28 million	Tiered, Symmetric	Recognize rates differences in actual net power costs from those assumed in base energy rates

Overview of Power Cost Adjustments in Pacific Northwest

PCA's	Dead-Band	Dead-Band % of Revenue	Sharing 1	Sharing 2	Sharing 3	Outside Sharing-Band
PGE Hydro	$2.5 million	0.14%	100%	100%		
Avista WA	$9 million	2.45%	90%			
Avista ID	$0		90%			
Idaho Power ID	$0		90%			
PSE	$20 million	1.47%	50%	90%	95%	99%

January 26, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated January 5, 2004
Question 008

Request:

Mr. Kuns testifies, based on an example that assumes that excess hydro in good years has the same market value as lost hydro in bad years, that any resulting rate charges or credits are likely to be small in a given year. Assuming that PGE's proposed HGA mechanism was put in place beginning in 2001, using actual monthly on- and off-peak Mid C prices, show what the resulting charges or credits (in dollars and in cents/kWh) would have been in 2002, 2003, and 2004.

Response:

PGE objects to this request on the basis that it is unduly burdensome. CUB has the information necessary to perform the calculations. Nevertheless, without waiving objection, PGE replies as follows:

Actual and projected output at PGE's hydro facilities can be calculated from the data provided in response to CUB Data Request No. 002-B. Loads are provided in our response to CUB Data Request No. 002-A. In addition, Attachment 008-A provides the requested monthly on- and off-peak Mid-C prices.