

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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OF OREGON**

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PORTLAND GENERAL ELECTRIC,) OPENING TESTIMONY OF
Application for a Hydro Generation Power) THE CITIZENS' UTILITY BOARD
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1 Our names are Bob Jenks and Lowrey Brown, and our qualifications are listed in
2 CUB Exhibits 101 and 102 respectively.

3 **I. Introduction**

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

9 In our testimony, we will provide analysis of PGE's proposed mechanism that
10 clearly demonstrates that it does not meet a just and reasonable threshold, we will discuss
11 PGE's approach to the problem, we will address why we believe that PGE is not

1 addressing the correct issues, and finally, we will recommend what the Commission
2 should do in this docket.

3 **II. PGE's Proposed Hydro Generation Adjustment**

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

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

18 **A. It Is Neither Just Nor Reasonable**

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

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

5 **i. What Theoretically Happens In A Good Hydro Year**

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

11 Instead, a utility with excess low-cost hydro combined with lower-than-projected
12 market prices, would reduce the output of its higher variable-cost generation and replace
13 this with self-generated hydro and lower-cost purchased power. PGE’s hydro mechanism
14 assumes a company would continue to produce power when the variable cost of that
15 power is greater than market prices, even though the company has excess hydro
16 generation available to replace that more-expensive generation. A prudent company,
17 however, would use the excess hydro to replace generation that costs more than this new,
18 lower market price.

19 **ii. What Theoretically Happens In A Bad Hydro Year**

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

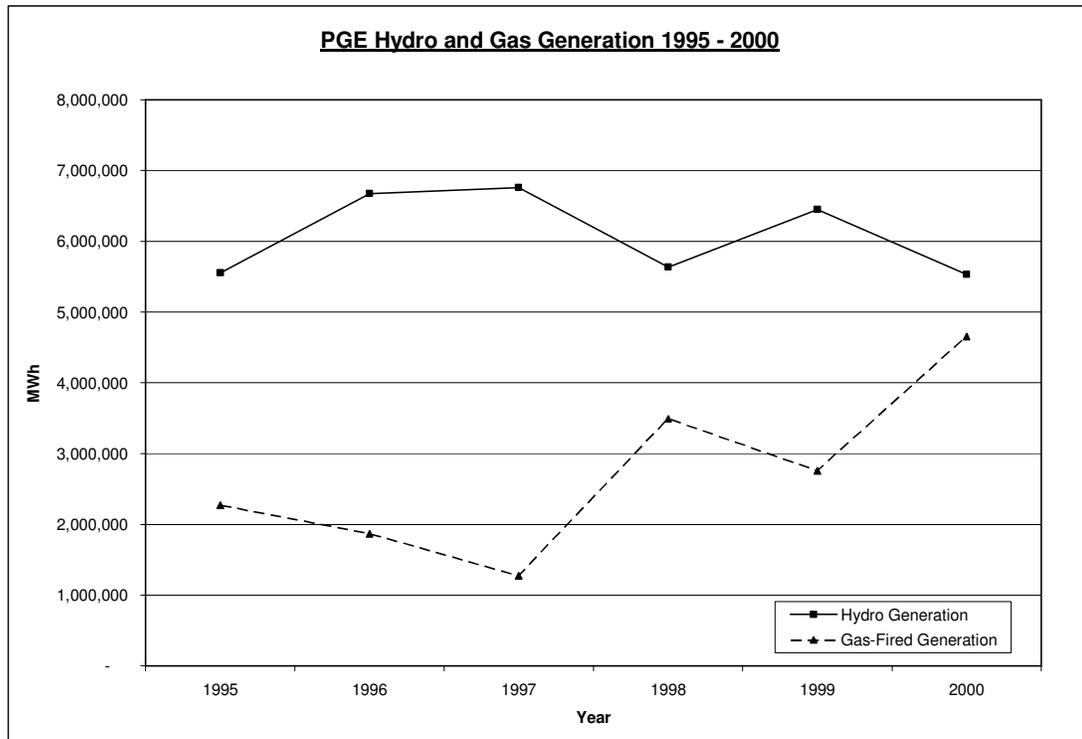
1 Higher market prices make a utility's marginal units more cost-effective, and a
2 prudent utility will use these units to replace the lost hydro, as long as it can do so at a
3 cost below the new, higher market price. Maintenance schedules of other plants might be
4 adapted in a manner as to reduce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

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

17 **iii. What Actually Happens In A Good Water Year**

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

1 effect, and customers would have been shortchanged in receiving the benefit of the good
2 hydro.



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

1 **iv. What Actually Happens In A Bad Water Year**

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

8 MONET, the model PGE uses to project annual power costs, dispatches resources
9 based on load, market prices, and available resources. We can use MONET to compare
10 PGE's power cost projections from its 2002 and 2003 RVM calculations to what PGE's
11 power costs would have been under the exact same conditions except for updating the
12 MONET run with actual hydro generation and actual market prices. This comparison
13 shows, by holding all variables except hydro and market prices constant, how MONET
14 dispatches PGE's resources differently to account for changes in these two factors. PGE's
15 HGA is designed to isolate hydro generation and market prices from all other factors,
16 therefore, it is useful to see what happens when those two variables are isolated in
17 MONET.

18 We did this comparison. CUB Exhibits 104 and 105 are the MONET runs PGE
19 filed in UE 115 and UE 139 projecting power costs for 2002 and 2003. CUB Exhibits
20 106 and 107 are these MONET runs updated with actual hydro generation and market
21 prices. The results show that thermal resources are dispatched to replace some of the
22 hydro shortfall and minimize power costs. In addition to this, we also calculated what
23 PGE's HGA would have charged customers for those years in order to compare what low

1 hydro costs the Company to what the Company would charge customers for the lost
2 hydro.

3 We looked at the following to make the comparison:

- 4 • *Projected Power Costs from MONET* – This data is from the original MONET
5 runs that established power costs for the UE 115 and UE 139. CUB Exhibits
6 104 and 105.
- 7 • *Power Costs Adjusted for Actual Hydro & Market Prices* – This data is from
8 MONET runs using all of the original data except hydro generation and market
9 prices which were updated with the actual data. This represents how PGE
10 would have dispatched its system in a scenario with the projected variables and
11 the actual hydro generation and market prices. In keeping with PGE’s
12 proposed HGA, it allows us to isolate hydro and the associated market prices.
13 CUB Exhibits 106 and 107.
- 14 • *The Cost of Low Hydro* – This represents what the low hydro actually cost
15 PGE, given that PGE would dispatch its other resources differently under the
16 above two scenarios.
- 17 • *PGE’s HGA Charge* – This is an approximation of what PGE’s HGA
18 mechanism would have charged customers for the lost hydro. Please see CUB
19 Exhibit 108-Errata.
- 20 • *Overcharge* – This is the amount PGE would have charged customers
21 BEYOND what it actually would have cost them to replace the power lost due
22 to low hydro.

23 BEGIN CONFIDENTIAL MATERIAL

24

25

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1 **B. PGE’s HGA Is Inconsistent With Its Own Least Cost Plan**

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

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

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

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

22 CUB Exhibit 109

23 Unfortunately, PGE’s proposed HGA mechanism is not compatible with these
24 guidelines. Customers pay the fixed costs – the premiums – for the hedges, as well as the
25 fixed costs associated with duct firing, but, under PGE’s proposed Hydro Generation
26 Adjustment, customers would be charged as though all lost hydro were being replaced by
27 market power, and would never receive any value for the hedges and duct firing. PGE’s
28 own Least Cost Plan contains strategies to reduce the need to purchase power to replace

1 lost hydro, but PGE's HGA ignores this strategy to reduce costs, and charges customers
2 more than the actual cost of replacing lost hydro.

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

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

13 **i. Oregon Precedent Does Not Support Such A Generous Mechanism**

14 The most recent case that addressed hydro variability was UM 1071, PGE's 2003
15 hydro deferral. In that docket, PGE proposed a 95/5 sharing mechanism, where 95% of
16 the costs of changes in Net Variable Power Costs (NVPC) would fall on customers.
17 Order 04-108. In addition, the time lag between the beginning of the year, and the date
18 upon which PGE actually filed the mechanism would act as a dead-band. According to
19 the Commission Order 04-108, PGE's proposal would require the Company to absorb
20 18% of its excess Net Variable Power Costs for 2003. Yet the Commission rejected the
21 Company's filing, and instead suggested that the, "parties might present a PCA proposal
22 similar to the one Staff outlined here." Order No. 04-108. Staff's proposal was for a PCA
23 that protected the Company from extreme events only.

1 PGE argues that it has had a PCA at various times in the past, and that such a
2 mechanism is not out of the ordinary in Oregon regulation. What they did not say, is that
3 those PCAs were not nearly as generous as what they are proposing now. CUB Exhibit
4 110 is the Company's answer to CUB Data Request 11 which shows the PCA history that
5 PGE cites. It shows that the Company's PCAs over the last 20 years have had sharing
6 mechanisms with the utility typically absorbing 20% to 50% of the cost associated with
7 the PCA. The two most recent PCAs had tiered sharing-bands, where the utility paid 50%
8 of the costs until they reached a certain level, and then customers absorbed a greater
9 share. In addition, these two PCAs had dead-bands where the utility was required to
10 absorb the first \$28 to \$35 million in higher costs. CUB does not believe that this history
11 supports a mechanism with no sharing and a dead-band of just \$2.5 million.

12 **ii. Regional Precedent Does Not Support PGE's Proposal**

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

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

1 proposing. As a percent of revenue, the dead-bands in Washington are more than 10
2 times greater than what PGE is proposing here.

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

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

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

17 **E. PGE's HGA Mechanism Has No Analytical Support**

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

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

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

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

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

21 PGE/700/Kuns/8

22 CUB Exhibit 108-Errata shows what the result of PGE mechanism would be in
23 2002, 2003, and 2004. We compared projected and actual monthly hydro output, and
24 used actual monthly on- and off-peak market prices. Rest assured, the resulting rate
25 charges are not small. PGE’s HGA would have charged customers approximately

1 \$3 million in 2003, \$9 million in 2004, and \$15 million in 2005. On top of this,
2 customers would owe an additional \$31 million to the Company.

3 **F. PGE's ROE Claims Are Largely Irrelevant**

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

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

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

21 Order 04-108, page 10-11

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

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

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

6 **A. Hydro Variability & Climate Change**

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

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

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

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

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

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

21 Owing to human activities, the atmospheric concentrations of dozens
22 of greenhouse gases are increasing at a rate far exceeding any in the
23 last 10,000 years. Carbon dioxide has increased by some 33% since
24 1800; methane, over 150%; and there are many gases that are solely
25 man-made. These greenhouse gases increase the heat-trapping

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

3 PGE/400/Mote/4

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

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

10 PGE/100/Lesh/19

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

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

1 **IV. CUB Recommendations**

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

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

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

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

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

1 **A. Recommended Principals**

2 In 2002, we recommended the following:

3
4 **2002 CUB Principles For A Hydro PCA**

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

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

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

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

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

32
33 CUB still believes that these 2002 principles are valid and provide useful
34 guidelines in designing an adjustment mechanism, but it is worth updating them and
35 placing them in the current context.

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

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

7 **ii. A PCA Should Be Asymmetrical**

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

1 **iii. A PCA Should Be Narrowly Defined In Scope**

2 A PCA or hydro-only PCA should be as limited as possible. In 2002, we argued
3 against including lost revenues in a PCA. Today, we generally agree with PGE that the
4 risk we are trying to address is one associated with hydro, and, therefore, a PCA should
5 be limited to hydro and electric prices – though we would argue that a better way to
6 calculate the cost of lost hydro is to run MONET adjusted for actual hydro and market
7 prices. A hydro-only PCA doesn't have to ignore the flexibility provided by a company's
8 thermal generation, hedges, and other resources.

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

13 **iv. A PCA Should Hold Management Accountable**

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

19 **v. A PCA Should Include Customer Protections**

20 A PCA should include some of the protections associated with deferrals. In 2002
21 we recommended that PCA balances should be placed in deferred accounts so customer
22 protections associated with deferrals, which are missing from automatic adjustment

1 clauses can be applied. Whether a deferral is used or not, we believe that a PCA should
2 explicitly contain the protections we have been concerned about:

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

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

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

18 Appropriate Amortization Time-Period. In addition, the risk of a 1-in-10 bad
19 hydro year is 1-in-10 years. If you were to spread the amortization of a 1-in-10 hydro
20 event out over 10 years, customers would be fairly and equally paying for the risk of poor
21 hydro. In reality, we do not want to fix it so tightly, because it is possible to have a 1-in-
22 10 year hydro event twice in four years, but it is a reasonable regulatory policy to spread
23 the amortization of such an event out over a number of years.

1 **B. Recommended Actions**

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

3 **i. Deny PGE's proposed HGA**

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

7 **ii. Do Not Make This Order Retroactive**

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

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

1 **iii. Issue A Draft Order**

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

10 **iv. Conduct An Investigation Into The Least-Cost Approach**

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

21 **v. Consider Demand Response**

22 Part of the strategy to deal with low hydro should involve customers. The PUC
23 should consider guidelines for when demand response programs are triggered during

1 serious low hydro events. When market prices spike, demand response programs focused
2 on immediate results may become cost-effective. This can include simply asking
3 customers to reduce their usage. During the energy crisis of 2000-2001, a 1-in-50 event,
4 customer response programs targeting all classes of customers were implemented.
5 Customers were encouraged to conserve energy. These programs worked; customers did
6 cut back.

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

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

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

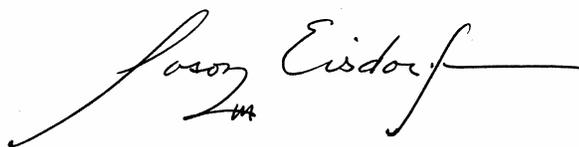
20 **V. Conclusion**

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

CERTIFICATE OF SERVICE

I hereby certify that on this 24th day of February, 2005, I served the foregoing Errata 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 6 confidential copies to the Commission's Salem offices.

Respectfully submitted,



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February 24, 2005

Public Utility Commission of Oregon
PO Box 2148
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Re: UE 165 CUB Opening Testimony Errata

Enclosed are replacement pages for CUB's opening testimony in UE 165 to fix a calculation error in our estimate of PGE's proposed HGA for 2002 through 2004. The error involved copying and pasting PGE's actual hydro generation data, which contained a formula for the Company's share of the Pelton and Round Butte Complex. As a result, the original calculations did not include PGE's actual generation from those dams.

Please replace original pages 7, 8, 13, 14, and Exhibit 108 with the enclosed, updated pages.

Respectfully submitted,

Bob Jenks
Executive Director

Lowrey R. Brown
Utility Analyst

1 hydro costs the Company to what the Company would charge customers for the lost
2 hydro.

3 We looked at the following to make the comparison:

- 4 • *Projected Power Costs from MONET* – This data is from the original MONET
5 runs that established power costs for the UE 115 and UE 139. CUB Exhibits
6 104 and 105.
- 7 • *Power Costs Adjusted for Actual Hydro & Market Prices* – This data is from
8 MONET runs using all of the original data except hydro generation and market
9 prices which were updated with the actual data. This represents how PGE
10 would have dispatched its system in a scenario with the projected variables and
11 the actual hydro generation and market prices. In keeping with PGE’s
12 proposed HGA, it allows us to isolate hydro and the associated market prices.
13 CUB Exhibits 106 and 107.
- 14 • *The Cost of Low Hydro* – This represents what the low hydro actually cost
15 PGE, given that PGE would dispatch its other resources differently under the
16 above two scenarios.
- 17 • *PGE’s HGA Charge* – This is an approximation of what PGE’s HGA
18 mechanism would have charged customers for the lost hydro. Please see CUB
19 Exhibit 108-Errata.
- 20 • *Overcharge* – This is the amount PGE would have charged customers
21 BEYOND what it actually would have cost them to replace the power lost due
22 to low hydro.

23 BEGIN CONFIDENTIAL MATERIAL

24

25

26

27

28

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

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

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

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

21 PGE/700/Kuns/8

22 CUB Exhibit 108-Errata shows what the result of PGE mechanism would be in
23 2002, 2003, and 2004. We compared projected and actual monthly hydro output, and
24 used actual monthly on- and off-peak market prices. Rest assured, the resulting rate
25 charges are not small. PGE’s HGA would have charged customers approximately

1 \$3 million in 2003, \$9 million in 2004, and \$15 million in 2005. On top of this,
2 customers would owe an additional \$31 million to the Company.

3 **A. PGE's ROE Claims Are Largely Irrelevant**

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

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

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

21 Order 04-108, page 10-11

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