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July 21, 2005

Via U.S. Mail and Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferral of Costs and Benefits Due to Hydro Generation Variance
OPUC Docket No. UM 1187

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five (5) copies of the following Testimony:

PGE/200: Rebuttal Testimony of Pamela Lesh and Jay Tinker.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

DCT:am

cc: UM 1187 Service List

Enclosure

CERTIFICATE OF SERVICE

I certify that I have caused to be served the accompanying **Rebuttal Testimony of Portland General Electric in Docket UM 1187** by mailing a copy by First Class U.S. Mail, postage prepaid and properly addressed, and by electronic mail, to the following persons on the official service list maintained by the Commission:

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Dated this 21st day of July, 2005.

DOUGLAS C. TINGEY

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Hydro Generation Variance
UM-1187

PORTLAND GENERAL ELECTRIC COMPANY

REBUTTAL TESTIMONY OF

Pamela G. Lesh
Jay J. Tinker

July 21, 2005

UM-1187 / PGE / 200
LESH - TINKER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

SD-PCAM SCOPE & DESIGN

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony of

Pamela G. Lesh
Jay J. Tinker

July 21, 2005

I. Introduction

Q. Please state your names and positions with PGE?

A. My name is Pamela G. Lesh. I am PGE's Vice President for Regulatory Affairs and Strategic Planning. I sponsored PGE Exhibits 100 and 800 in Docket UE-165. My qualifications were provided at the end of PGE Exhibit 100.

My name is Jay Tinker. I am a Project Manager in the Rates and Regulatory Affairs Department. I sponsored PGE Exhibits 300 and 900 in Docket UE-165, PGE Exhibit 100 in Docket UM-1187, and PGE-Staff Exhibit 100 in Dockets UE-165 and UM-1187. My qualifications were provided at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM) as a reasonable mechanism for reflecting within PGE's cost of service rates the highly variable production of our hydro-electric resources, both owned and contractual. We explain why the concerns raised and positions taken by ICNU and CUB in ICNU Exhibit 100 (in Docket UM-1187) and CUB Exhibit 200 (in Dockets UE-165 and UM-1187) should not cause the Commission to reject the SD-PCAM.

Q. How is your testimony organized?

A. Our testimony addresses the scope and design issues other parties raise regarding the SD-PCAM. Section II covers:

- Scope of the SD-PCAM, which unlike a general power cost adjustment (PCA), adjusts rates only for hydro production and generating plant dispatch changes caused by fluctuations in natural gas and electric power market prices
- Design of the SD-PCAM

- Use of indices to value hydro production changes and create a comparison forecast of the generating plant dispatch changes based on actual spark spread
- Use of Monet to perform the comparison forecast
- The dead-band used in the SD-PCAM
- Other scope and design issues
- A current estimate of the result of the SD-PCAM for 2005

II. The Scope and Design of the SD-PCAM

Q. For the convenience of readers, please review the scope and design of the SD-PCAM.

A. At the heart of the adjustment mechanism is the System Dispatch Cost Variance (SDCV). The SDCV is a measure of both the hydro-related changes in the net variable costs projected in PGE's RVM and the changes in the dispatch of PGE's thermal plants from that forecast in the RVM related only to changes in electric and gas wholesale prices, in other words – related to the spark spread. The SDCV uses published indices (Dow Jones Mid-Columbia Daily and Hourly Electricity and Platts GasDat Daily) to calculate the "value" of hydro production changes and to dispatch PGE's thermal plants. We supply these inputs to our Monet power forecasting model, holding constant all other inputs in place as of the final run used for that year's RVM. The result is a "back-cast" power cost forecast; in other words, the forecast we would have used for ratemaking had we known exact hydro production and electric and natural gas prices for that year. To the SDCV, the mechanism applies the dead band of $15 million on the increased cost side and $7.5 million on the decreased cost side, sharing the remainder 80-20 to customers and PGE, respectively.

Q. Do any parties to these proceedings dispute the scope and design of the SD-PCAM?

A. Yes. Both CUB and ICNU take various positions and raise concerns regarding the SD-PCAM's scope and design. For example, CUB questions the exclusion of load variations, particularly the mechanism's failure to adjust for customer conservation. CUB also raises a concern with the use of Monet to create the comparison forecast and takes the position that a mechanism should use "actual costs." ICNU complains that the mechanism includes more than just hydro production changes. ICNU also takes the position that the electric price index the SD-PCAM uses is not correct.

Q. As a general matter, would it be possible to construct an adjustment mechanism that addressed all concerns and satisfied all complaints against the SD-PCAM?

A. No. Designing a mechanism to address all of the concerns and positions would require the impossible because these concerns and positions represent conflicting objectives. For example, the mechanism cannot simultaneously use "actual costs" and limit itself to changes in hydro production and gas and electric markets. It cannot adjust for conservation by PGE's customers without also adjusting for peak use and, in both cases, limiting such adjustments solely to the NVPC effects causes perverse financial results to PGE. Regulation cannot "optimize" on every objective; choices must be made. This is why PGE initially proposed criteria to use in judging various mechanisms. The SD-PCAM meets these criteria. The implication of many of the complaints is that leaving the effects of variable hydro production on cost of service unsolved is the better regulatory policy. We respectfully disagree.

Q. Does the SD-PCAM represent a series of reasonable choices among the alternatives for addressing the particular cost of service issue presented by hydro resources?

A. Yes. We acknowledge that a wide range of adjustment mechanisms exist that could address the difficulty of reflecting hydro variability in cost of service rates previously discussed in PGE Exhibit 100. The choices run from comprehensive power cost adjustments to focused mechanisms that concentrate on specific cost elements. Each choice has advantages and disadvantages. No mechanism can meet all objectives. The need to make choices should not dissuade the Commission from adopting a mechanism that reasonably accomplishes the task. Good regulatory policy does not ignore a given cost variance just because it is difficult to capture in rates set periodically.

Q. In the past, PGE has proposed comprehensive power cost adjustments. What caused you to propose a mechanism focused on hydro variability?

A. An advantage of comprehensive mechanisms is that they capture the numerous interactions of power operations and dispatch, some of which can offset each other over time. It is this integrated nature, however, that appears to have generated opposition in prior proceedings. For example, ICNU has opposed a broad-based PCA in the past. (Order 04-108, Page 4, and Order 04-357, Page 3, both in Docket UM-1071) The disadvantage is that comprehensive mechanisms raise complex questions, such as the effect of past wholesale sales strategies on a more recent short position or of maintenance strategies on plant performance. In particular, comprehensive mechanisms must answer questions such as:

- How to handle changes in load?
- How to address prudence issues associated with plant availability?
- How to ensure that plant dispatch and power purchase decisions are prudent?

Based on concerns expressed in prior proceedings and our desire to achieve a result acceptable to customer groups and Staff, we proposed a mechanism focused on hydro variability.

Q. Once you decided to request a focused mechanism, were there still a number of decisions that had to be made?

A. Yes. We still needed to determine how to calculate the impact of hydro variability on NVPC and what data to use in the calculation. As we pointed out in UM-1039 and the Commission Staff determined in UM-445 (Order No. 91-1781), the calculation of actual changes in NVPC due to a particular series of events is difficult if not nearly impossible. Therefore, we proposed a mechanism that measured the value of hydro production variances using objective market data. Both the actual hydro production and market prices are easy to verify and not subject to manipulation. After parties expressed concern that our proposal did not include the effects of unexpected hydro production increases or decreases on plant dispatch, we modified our proposal to do so.

The resulting SD-PCAM provides a reasonable estimate of the impact of hydro variations, as well as the effect of actual market fuel and electric prices on our plant dispatch. Thus, it "updates" the forecast we use to set rates in advance for information that cannot be known at that time and variables that PGE cannot influence, while leaving untouched other assumptions, such as how well PGE's generating resources will operate and our response to changing loads throughout the year. We have retained the advantages of our initial proposal in that it is still objective, verifiable and independent.

Q. Can you provide an example of testimony from the other parties that demonstrates conflicting objectives?

A. Yes. On Page 30 of ICNU Exhibit 100, ICNU states that "While the power costs reflected in rates are $7.0 million less than actual costs for January to March 2005, PGE has indicated that the SD-PCAM would defer $11.1 million during that period….The latter figure is based on PGE's best approximation of the results of the SD-PCAM deferral, without any dead band." ICNU is comparing the variance resulting from a comprehensive PCA to the variance resulting from the SD-PCAM. The smaller, PCA-based, number includes all changes to PGE's NVPC, including some to which ICNU has objected in the past, including load and plant availability. The comparison ICNU makes, and conclusion it draws, is incorrect for the simple reason that ICNU is not comparing numbers that are comparable. The change in "power costs reflected in rates" includes <u>all</u> changes to PGE's NVPC, including load, plant availability, and fuel and power transactions. The estimate of the SD-PCAM for these months isolates changes in hydro production and plant dispatch, using objective data. In addition, three months is an inadequate period from which to draw broad conclusions.

A. Scope

Q. What positions do CUB and ICNU take regarding the scope of the SD-PCAM?

A. Both challenge the mechanism's inclusion of plant dispatch changes related to spark spread changes and CUB objects to the exclusion of load effects on NVPC, particularly the effects of customer conservation.

Q. Are CUB and ICNU consistent in expressing concern because the SD-PCAM includes costs – plant dispatch changes based on spark spread – not strictly related to hydro variations?

A. No. In PGE's initial filing in Docket UE-165 on May 18, 2004, we proposed a Hydro Generation Adjustment (HGA) mechanism, which simply valued the deviations in hydro production from amounts assumed in PGE's RVM filings. CUB and ICNU took the position that this focus was too narrow, because optionality benefits from PGE's thermal plants could offset the cost of decreased hydro production. For example, ICNU explained that "[i]n all likelihood, this will overstate the cost of hydro variations because the Company has the option to run its gas-fired units when hydro generation is below normal and gas prices are low (relative to market)." (ICNU Exhibit 100 in Docket UE-165, Falkenberg at 7, Lines 19-21) See also CUB Exhibit 100, Jenks-Brown at 21, Lines 7-8. We agreed. Although the broad scope of electric and gas markets diminishes any relationship between hydro production in the West and the gas-electric spread, PGE's gas-fired plants and capacity contracts do serve as "caps" so to speak on the market price PGE could have to pay to replace missing hydro production. Similarly, under some circumstances, strong hydro production could allow us to displace gas-fired generation we had forecast to run in the RVM. The SD-PCAM will capture both effects, to the benefit of customers.

Q. Does the SD-PCAM adjust NVPC cost of service for the actual loads during a given year?

A. No, it does not adjust for load. As explained above, the mechanism produces only a new NVPC forecast using information that we could not know at the time we made the original forecast (hydro, gas and electric prices). It does not change the traditional allocation of load variation risk to PGE, an allocation that CUB appears to support. (CUB Exhibit 200, Page 10)

Q. Were PGE's actual loads lower than forecast during the first three months of 2005?

A. Yes, loads were lower during this period primarily because of mild weather. The residential load decreases from the RVM forecast documented in CUB Exhibit 202 are based on the data PGE provided in response to CUB Data Request No. 32. The data provided in PGE's response also indicate that, whereas PGE's overall system loads were 2.77 percent less than forecast over the first four months of 2005, on a weather-adjusted basis they were less than one percent below the forecast. In fact, in January and March, PGE's weather-adjusted overall system loads were greater than the RVM forecast.

Q. Does the SD-PCAM intend to reallocate the risks and rewards of load variation?

A. No.

Q. How then should the SD-PCAM incorporate load variations?

A. It should not consider them.

Q. Do PGE's investors currently bear the risk that reduced loads can result in less than full "fixed cost" coverage, as well as benefiting from greater than full fixed cost coverage in the case of increased loads?

A. Yes.

Q. What effect do decreased loads have on PGE's fixed cost coverage?

A. PGE's fixed costs are largely covered by "per kWh" rates. A portion of the charge for each kWh sold covers fixed costs. Rates are set so that, if actual loads equal forecasted loads, PGE recovers its fixed costs. If actual loads are higher, the contribution to fixed costs helps mitigate the potential effects of higher-priced power PGE must buy to meet the new loads, particularly if they occur on peak. If actual loads are less than forecasted, the savings in NVPC helps offset the loss of fixed cost coverage that results. The relationships between load, NVPC, and fixed cost recovery resulting from rate design is why PGE has maintained since early in this decade that any comprehensive power cost adjustment must account for load changes, either neutralizing them or adjusting for their margin recovery effects.

Q. Does CUB's testimony in these dockets indicate concern with the SD-PCAM's adoption of the past allocation of load risk to utilities?

A. Yes, it appears to. CUB states that "the backcast MONET run … will dispatch PGE's thermal assets and make market purchases as if the projected, normalized load had actually come to pass, which is not the case." (CUB Exhibit 200, Jenks-Brown at 8, Lines 3-6) CUB notes the decline in PGE's loads during the first few months of 2005 that we explained above. CUB also expresses particular concern that the SD-PCAM does not somehow credit customers for conservation, taking the position that this requires customers to pay for "phantom load." (CUB Exhibit 200, Page 12) In this regard, CUB cites a press release that was signed by CUB, PGE, and a number of other regional entities. The first sentence of the press release reads: "The Bonneville Power Administration, regional utilities and public interest groups today asked Northwest residents to help combat the economic effects of a dry winter by efficiently using electricity this spring and summer." In reference to the SD-PCAM, CUB then states that "Under this mechanism, however, the message to conserve now in order to mitigate the future rate impacts of the drought is misleading at best, because the amount deferred is calculated using projected loads, not the actual load that reflects customers' conservation. So customers' conservation reduces power costs for the utility, but the proposed mechanism will calculate costs for customers' bills as if they hadn't conserved at all. The Company will keep the benefit." (CUB Exhibit 200, Jenks-Brown at Page 11, Line 21 through Page 12, Line 3)

Q. Is CUB's testimony on load variation risk consistent?

A. No. On the one hand, CUB wants the SD-PCAM to include actual loads. On the other hand, CUB wants the risk associated with load variation to remain with PGE, as is currently the case. This is a contradiction. If PGE is to retain load variation risk, the SD-PCAM cannot update forecast loads to actual loads. The SD-PCAM is a targeted mechanism. It does not alter the allocation of load variation risk between PGE's investors and its customers.

Q. Does the SD-PCAM deprive customers of benefiting from conservation?

A. No, not at all. First, those customers who conserve energy benefit from lower bills. If a customer uses less energy, he or she is billed for less. This does not depend on mechanisms such as the SD-PCAM. Second, if "everyone" in the region conserved, regional demand would decrease, and power prices would tend to decrease, putting downward pressure on power costs. In particular, this would decrease the market prices used in the SD-PCAM.

Third, regional conservation would decrease BPA's costs which can have a direct impact on the prices paid by PGE's residential and small farm customers.

CUB's issue appears to be that the SD-PCAM does not credit to customers any decreases in NVPC related to conservation. As we explained above, however, the NVPC effects of load changes mitigate the effect of those same load changes on PGE and customers because of the related effects on fixed cost recovery. Conservation adversely affects PGE's short-term financial condition. If customers conserve, power costs decrease along with PGE's revenues. Except in the rare instance when marginal power costs are above the marginal rate, the net effect is a financial detriment to PGE.

Q. Can you provide an example to illustrate your points?

A. Yes. Suppose that market electric prices are $50/MWh under average hydro conditions, but $55/MWh under poor hydro conditions, consistent with PGE's hydro plants producing 400,000 MWh less than expected. Then poor hydro conditions impose a $22 million cost on PGE for replacement power (400,000 MWh x $55/MWh).

Conservation might offset the poor hydro output, but it would likely <u>increase</u>, rather than decrease, PGE's financial loss. Suppose that PGE's conserving customers have average rates of $65/MWh, and that substantial conservation across the region, and 400,000 MWh among PGE's customers, is sufficient to offset the hydro shortage and maintain market electric prices at $50/MWh. Then PGE's losses would <u>increase</u> from $22 million to $26 million. Conservation by PGE's customers would offset PGE's poor hydro output, making additional power purchases unnecessary. Hence, costs would not change. However, revenues would decrease by $26 million (400,000 MWh x $65/MWh), resulting in an overall net cost to PGE of $26 million.

B. Overall Design

Q. Do ICNU and CUB question the SD-PCAM's ability to measure power cost variations?

A. Yes, both ICNU and CUB express concerns about the ability of the SD-PCAM to accurately measure variations in PGE's costs. (CUB Exhibit 200, Pages 32-33; ICNU Exhibit 100, Pages 32-34) However, they do not identify by what methodology the SD-PCAM could "accurately" measure hydro-related NVPC variations.

Q. Is this position that the SD-PCAM is not "accurate" a reason to reject the mechanism?

A. No. Power supply and its related costs are very complex, and in reality, no mechanism can perfectly measure the effect of a change on one aspect of the system. For example, assume that on a given day within a year, PGE identifies both a forecast loss of hydro production and a forecast increase in load and makes a forward power purchase. For which change is that purchase an "actual" cost? The SD-PCAM eliminates this question by using outside data rather than PGE's actions to "value" the increased or decreased hydro production and changes in plant dispatch. Thus, no one will need to examine each power purchase, power sale and change in plant dispatch to determine whether it was hydro-related.

Q. Does CUB take the position that the SD-PCAM will overstate the expected financial effect on PGE of decreased hydro production?

A. Yes. On Pages 14 and 15 of CUB Exhibit 200, CUB notes that PGE will likely purchase replacement (for hydro) power ahead of time, if it knows that poor hydro conditions are likely. Then, if market prices increase between the time of purchase and the time of need, the SD-PCAM would overstate the change in PGE's net variable power costs.

Q. Is this position well supported?

A. No. This position assumes that either PGE is able to perfectly forecast market electric and gas prices and/or that the entire WECC will experience only rising markets in the future. Neither assumption has any factual support. If electric prices fall between the time PGE fills a shortfall and the time of the actual shortfall, the SD-PCAM will understate the direct costs to PGE of filling the shortfall. Prudent utility practice is to generally buy in advance to assure reliability, but there are no guarantees that this practice will produce the most economic result. Several of the contracts PGE entered into to replace 2005 hydro output resulted in losses, as the prices PGE paid for the power turned out to be greater than power prices reflected in the daily price indices. For example, during the period from November 2004 through January 2005, PGE purchased hydro replacement energy for the month of February 2005 at an average price of more than $50 per MWh. As it turns out, the value of that power when delivered over the month of February 2005 averaged only about $46 per MWh. Similarly, in an abundant hydro year, PGE may sell the additional anticipated power in advance, foregoing the gains of a rising market. In this instance, the mechanism will credit customers with more than PGE gained from the additional production.

The SD-PCAM shields customers from the effects of PGE's decisions, and thus concerns of prudence, by using objective market information. The use of market information will neither systematically overstate nor systematically understate the effects of hydro variation. It will calculate these effects, along with plant dispatch, according to the market.

Another fact that undercuts CUB's position is that expectations of hydro conditions can change substantially within the course of a year. PGE Exhibit 208 illustrates how much expectations of hydro conditions can change within just the first six months of a year. PGE has no ability to predict these changes. Under our proposed mechanism, if we purchase additional power in anticipation of low hydro, but hydro production turns out to be "normal," customers are held harmless. Similarly, if we sell anticipated excess hydro production ahead and later there is none, customers are held harmless.

C. Use of Indices

Q. Does ICNU dispute the gas and electric indices used in the SD-PCAM?

A. Yes. ICNU takes the position that the SDCV calculation should use reported hourly electric index prices, rather than "day-ahead" on and off-peak electric prices that we then shape into hourly prices based on the "day-of" report. The hourly index referred to by ICNU is a day-of index, which reports average prices of power transaction executed on the day of delivery

Q. Is this position supportable?

A. No. Use of the day-of electric prices advocated by ICNU would impair the SD-PCAM's ability to provide a redispatch of PGE's thermal plants that is consistent between electric and gas markets and with the "value" of changes in hydro production. The dispatch of PGE's gas plants depends on relative gas and electric prices at the time dispatch decisions are made. Hence, it is important that the SD-PCAM use consistent measures of gas and electric prices. The only reliable gas index available is a day-ahead one, i.e. one that indicates "the price today for delivery tomorrow." Since we are restricted to a day-ahead gas index, we need to use a corresponding day-ahead electric index. In addition, the actual dispatch of our gas plants is primarily a function of day-ahead rather than day-of market prices. As we noted in PGE Exhibit 100 (in Dockets UE-165 and UM-1187): "Relying primarily on the daily day-ahead price index maintains consistency with the actual day-ahead natural gas prices to be input into Monet. Consistency is important to obtaining a realistic dispatch of PGE's resources." (PGE Exhibit 100, Galbraith-Tinker at 4, Lines 2-4)

Q. Why does ICNU take this position on the index?

A. It appears that ICNU believes that the day-of index will produce higher prices – and, thus, greater value for hydro production changes – than the day-ahead index. ICNU states that "as the data shows, the daily Dow Jones [day-of] index produces prices that are typically $1/MWh higher." (ICNU Exhibit 100, Falkenberg at 33, Lines 14-15)

Q. Is ICNU's conclusion well-supported?

A. No. ICNU relies on data for only the first three months of 2005 in reaching this conclusion. This is a very limited observation period. ICNU's conclusion would generally be correct in rising electric markets and incorrect in declining markets, and it says nothing about any differences in natural gas prices. ICNU's argument simply obscures the purpose of the Monet back-cast's redispatch of PGE's thermal plants, which is "obtaining a realistic dispatch of PGE's resources."

D. Use of Monet

Q. Do you agree with ICNU's concern over using Monet to produce the "back cast?" (ICNU Exhibit 100, Page 32)

A. No. ICNU misunderstands Monet's limitations in forecasting actual plant dispatch as the spark spread changes throughout a year with its ability to "back cast" plant dispatch accurately using the exact spark spread that occurs. The power production of PGE's gas-fired plants depends on relative gas and electric prices at the time dispatch decisions are made. This is clearly demonstrated in PGE Exhibits 902 and 904. Monet's dispatch of

PGE's gas-fired plants for RVM filings is inevitably different than what actually occurs, as the RVM filing must rely on forward gas and electric curves, whereas actual dispatch depends on gas and electric prices at the time of dispatch decisions. However, this fact certainly does not invalidate the use of Monet in the SD-PCAM, as the SD-PCAM is based on gas and electric prices coincident with dispatch decisions. Within the SD-PCAM, Monet provides an accurate back-cast.

Q. Is CUB's concern that the SD-PCAM uses "computer modeled power costs, not actual ones" well founded?

A. No. We cannot isolate the adjustment to rates of only certain NVPC changes without using a model and objective third-party inputs. Even if we could methodically record every reason for every change we make during a year affecting NVPC, in many instances more than one reason would drive the change and cause any mechanism to change cost of service for more than hydro production and plant dispatch based on spark spread.

E. Dead-Band

Q. What position do CUB and ICNU take on the size of the SD-PCAM's dead band?

A. CUB and ICNU both take the position that the SD-PCAM's dead band ($15 million for higher than expected costs, $7.5 million for lower than expected costs) is too small. (ICNU Exhibit 100, Pages 20-21; CUB Exhibit 200, Pages 17-18)

Q. Is this position well supported?

A. No. Neither offer much support for this position, which appears to rest on two 2001 Commission decisions. One of these approved a settlement for a temporary power cost deferral and the other was a decision on a power cost deferral after a contested case. In both cases, the calculation for the deferral included all variances in NVPC. Neither case addressed a focused mechanism for reflecting an individual highly variable component in cost of service rates.

Even if this one decision and one settlement were persuasive precedent, the SD-PCAM has a much narrower scope than the temporary mechanisms in the decision and settlement. To the extent regulatory policy supports the use of a dead band in this instance, the narrower scope should require a smaller dead band. In addition, it is not at all clear that the dead band should be greater than zero. In Oregon, Northwest Natural Gas has a gas cost adjustment mechanism with no dead band, and, as shown in CUB Exhibit 111, Avista and Idaho Power Company have PCAs in Idaho, both of which are broader in scope then the SD-PCAM and have no dead bands.

CUB also offers the explanation that "Reducing the cost side of the dead band from $40 million to $15 million is not justified by the exclusion of load variability and updated contracts, as Staff witness, Galbraith, contends." (CUB Exhibit 200, Jenks-Brown at 18, Lines 9-11) CUB does not quantify its analysis. Even had CUB done so, however, the analysis would not have supported the conclusion because the SD-PCAM leaves out other significant and potentially sizable sources of variance, such as thermal plant performance.

F. Other Design Issues

Q. Please respond to ICNU's claims that implementation of the SD-PCAM would result in retroactive ratemaking. (ICNU Exhibit 100, Pages 5-6)

A. This claim is a legal argument. PGE will respond to the argument in its legal briefs.

Q. Does ICNU offer an additional reason for its position that the SD-PCAM is biased?

A. Yes. On Pages 9 and 10 of ICNU Exhibit 100, ICNU states that the SD-PCAM is biased in favor of PGE's investors because PGE could have known the results of the mechanism for January and February 2005 when we reached agreement with Staff on the mechanism in early March. ICNU also offers a comparison of this alleged bias to a result that could occur under a "generation performance incentive mechanism" that ICNU describes. It is unclear how this incentive mechanism relates to the SD-PCAM, which is a cost recovery mechanism.

Q. Does this reasoning support ICNU's position?

A. No. At most, in March 2005, PGE had an estimate of what variance a mechanism might produce, not just the SD-PCAM. Given the extremely poor hydro conditions at the time, it is hard to imagine what proposed mechanism would not have produced some positive value for the difference between the hydro production assumed in setting rates and the hydro production that was actually occurring. We could not know, however, what the subsequent months would bring and could not estimate the ultimate result of applying the SD-PCAM's sizable dead band and sharing percentages to any variance that might still exist at the end of the year. And, of course, we could not know what the mechanism would produce in 2006.

Q. Is ICNU's position that PGE's rates already include hydro variability supportable? (ICNU Exhibit 100, Page 16)

A. No. First, ICNU's statements and the example on Page 17 of ICNU Exhibit 100 do not accurately reflect hydro treatment in Monet. We do not run Monet multiple times with varying hydro conditions and then average the NVPC results. For reasons discussed on Pages 15-16 of PGE Exhibit 300, we do not currently have the complex modeling necessary to do so. Instead we use a single synthetic hydro year consisting of the average of available hydro data. ICNU acknowledges this difference in its footnote on Page 16 of ICNU Exhibit

100 but then states that "this approach is not conceptually different from the method shown in the table." That conclusion might be the case if there were no interaction between variables in the model, such as between market prices and hydro conditions. Such interaction does exist, however, and ICNU cannot prove the contrary. Basic economics tells us that market prices during relative shortages (adverse hydro conditions) will be higher that those during relative surpluses (favorable hydro conditions). Thus, the financial consequences of good and bad hydro conditions are unlikely to offset each other over the long run. PGE Exhibit 301 provides illustrative examples, pointing to the likely result that the financial consequences of bad hydro conditions outweigh those of good hydro conditions.

Second, the SD-PCAM can result in either collections from, or payments to, customers. ICNU's position rests on only one of the two possible results of the SD-PCAM.

Although ICNU is correct that the settlement Staff and PGE support puts the SD-PCAM in place for only two years, ICNU has no factual basis for a conclusion that favorable hydro conditions in 2006 could not exceed the end result of the mechanism for 2005, particularly given the asymmetric dead band. In addition, the two year limitation is for settlement purposes only, and allows a re-examination of this entire topic in the context of a general rate case. PGE's agreement to this condition does not lessen our commitment to a long-term ratemaking treatment of this cost of service variance.

Q. Does ICNU express concern about the lack of a review process for deferrals under the SD-PCAM? (ICNU Exhibit 100, Page 26)

A. Yes. ICNU is correct that the Stipulation does not discuss the review process. This does not imply, however, that no review will occur. At a minimum, amortization of any collection or refund under the SD-PCAM will require a tariff filing and, thus, trigger all of the statutory and Commission processes pertaining to tariff filings. The review process will include the ability to examine the Monet model and results, including changes made to implement the Stipulation.

Q. CUB discusses various claims made by both PGE and CUB concerning the inclusion of updated gas prices in the Monet back-cast, which is a part of the SD-PCAM. (CUB Exhibit 200, Page 23-26) Please respond to this discussion.

A. We apologize if we misunderstood CUB's original comments and are pleased if we are in agreement with CUB that it is necessary to update both electric and natural gas prices. We discussed above the appropriate electric and gas price indices to use in the SD-PCAM's Monet back-cast. PGE Exhibit 900 discusses at length the need to update both electric and gas prices in the back-cast.

Q. Do you agree with CUB that PGE and its stakeholders should continue to look for ways to minimize the cost of hydro variability? (CUB Exhibit 200, Page 33)

A. Yes. Although Dockets UE-165 and UM-1187 are concerned with the cost of service effects (positive and negative) of variable hydro production, we agree with CUB that it is very important to minimize the cost of hydro variability. We analyze hydro risk in our integrated resource planning process. For our most recent IRP cycle, Chapter 6 of the 2002 Integrated Resource Plan and Pages 16-21 of the Supplement, 2002 Integrated Resource Plan provide our hydro risk analysis. As discussed on Pages 22 through 24 of PGE Exhibit 200, PGE has tried to negotiate a hydro hedge. Unfortunately, no counter-parties were willing to offer suitable products.

We are open to suggestions on how to manage hydro risk. However, there is no "magic solution," and given recent developments, hydro risk is likely to remain higher than in the past.

Page 19 of PGE Exhibit 200 includes a discussion of how the region has become "thermalized" over the past several years. Gas-fired plants are the marginal resource, and, given high gas prices, the financial consequences of hydro deviations are significantly greater than in the past, and likely to remain so. That is the context of the proposed SD-PCAM.

G. Current SD-PCAM Estimates

Q. Will the proposed SD-PCAM result in collection from customers in 2005?

A. We do not know. The result of the SD-PCAM will depend on the level of hydro generation and market electric and gas prices for the remainder of the year. These factors have changed throughout the year, and will continue to do so.

Q Have you provided any estimates of the financial impact of the variance in hydro generation?

A. Yes. The amendment to PGE's deferral application in UM-1187, filed on January 21, 2005, contained an estimated deferred amount of approximately $40 million. In response to a data request from ICNU, in April PGE provided an estimate of the SD-PCAM variance for the first three months of 2005 of $11.116 million, or more than $44 million on an annualized basis.

Q. Have hydro conditions improved since those estimates were provided?

A. Yes, hydro conditions have improved.

Q. Does PGE have a more recent estimate of the 2005 variance under the SD-PCAM?

A. Yes. A June 23, 2005, estimate, using the Monet model containing most of the changes necessary to implement the SD-PCAM, and using actual gas and electric prices through May with projections for the remainder of the year, shows an estimated variance of approximately

$17.5 million. With the dead band and sharing parameters of the SD-PCAM, this would result in a charge to customers of $1.97 million.

Q. Does an estimated variance much smaller than originally estimated diminish the need for the SD-PCAM in 2005?

A. No. We do not know what the final 2005 result will be. The situation may stay the same, continue to improve, or worsen. The SD-PCAM was reached by settlement as a theoretically sound approach without regard to how events turned out. It is still theoretically sound.

Q. Does this conclude your testimony?

A. Yes.

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