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GENERAL COUNSEL DIVISION

November 20, 2006

Filing Center
Public Utility Commission of Oregon
550 Capital Street, NE
Salem, Oregon 97301

Re: UE 180/UE 181/UE 184

Dear Filing Center:

Enclosed for electronic filing is an amended version of the non-confidential version of the Staff Opening Brief. The non-confidential version of the Staff Opening Brief previously filed with the Public Utility Commission of Oregon is different from the confidential version filed on that day in several respects. The non-confidential version filed on Friday, November 17, 2006, is a draft incorrectly filed as the final non-confidential Staff Opening Brief. Most notably, the non-confidential Staff Opening Brief filed on November 17, 2006, mistakenly reports that staff's overall return on revenue estimate is 7.7 percent, rather than 7.8 percent, omits three lines of text on page 18 and four lines on page 21, does not completely match up, page-wise, with the confidential version and includes several typographical errors corrected in the final confidential Staff Opening Brief.

A hard copy of this corrected brief is being served today on all parties on the service list that did not sign the protective order.

Thank you for your attention.

Very truly yours,

Stephanie S. Andrus
Assistant Attorney General

Enc.
c.   Service list

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

STAFF OPENING BRIEF

November 17, 2006

I. Introduction.

A pervasive weakness in the testimony and exhibits presented by Portland General Electric Company ("PGE") is PGE's failure to meaningfully address the concerns and issues raised by other parties in the case. PGE repeatedly either fails to address issues or arguments raised by other parties, or addresses them only in sursurrebuttal, after the other parties' opportunity to file testimony has passed. For example:

- The Commission's policy, made clear by several orders issued since the Western Power Crisis, is that utilities shall bear costs associated with normal business variability. Notwithstanding this policy, PGE asks the Commission to adopt a power cost adjustment mechanism that will shift to customers 90% of all net variable power costs ("NVPC") that exceed those included in rates. PGE did not acknowledge the Commission's policy, let alone address why it should not apply, until its sursurrebuttal testimony.[1]

- In light of the policy described above, staff of the Public Utility Commission of Oregon ("staff"), the Industrial Customers of Northwest Utilities ("ICNU"), and the Citizens' Utility Board ("CUB") testified in their direct and surrebuttal testimony that any power cost adjustment mechanism adopted by the Commission must have a deadband. In direct and rebuttal testimony, PGE merely argued that a deadband is not necessary or appropriate. However, it its last round of testimony, PGE described a deadband that the Commission should adopt if the Commission decides that one is necessary.[2] Because PGE saved this discussion for its last round of testimony, no party has opportunity to comment on the reasonableness of PGE's proposal.

- Staff recommends that the Commission indicate a preference for stochastic modeling to incent PGE to develop and rely on such modeling for ratemaking purposes. PGE acknowledges that its current modeling does not capture uncertainty but nonetheless opposes the recommendation and fails to propose an alternative to address the infirmities of using deterministic modeling for rate-setting purposes.

- Staff, ICNU, and CUB recommend that the Commission adjust PGE's NVPC to take into account "extrinsic value" of certain resources that is not captured by PGE's deterministic modeling. PGE acknowledges that its modeling does not capture this value, but opposes the adjustment on the ground that certain

[1] *See* PGE/2400, Lesh/9-21.
[2] PGE/2400, Lesh/21-22.

other costs are not captured by its modeling either. PGE argues that the Commission should therefore not "cherry pick" extrinsic value for rate-setting purposes. In other words, rather than engage in a discussion of how its modeling can be improved, or how the results of its modeling can be adjusted to better capture actual costs and revenues, PGE recommends the Commission simply ignore the deficiencies and accept PGE's modeling as it is.

- PGE's proposed NVPC includes costs associated ancillary service sales, but not offsetting revenues. Staff recommends that the Commission correct this mismatch by including revenues from PGE's ancillary service sales in PGE's NVPC. PGE does not address the policy reason underlying this proposal, but merely argues that because there is uncertainty regarding the levels of revenues, both ancillary sales revenues and costs should be "handled" under a comprehensive variance tariff. PGE's response to staff's concern regarding the mismatch of costs and benefits does not address the concern, but merely tables it while PGE continues to enjoy the benefit of the mismatch.

- PGE relies on results of a "risk-positioning model" performed by its expert witness. The Commission rejected the "risk-positioning model" in PGE's last general rate case. The Commission's guidelines for cost of equity witnesses require PGE to explain why the Commission should rely on the model in this case when it was previously rejected in another case. Even though staff pointed out that PGE is required to explain why the Commission should adopt the previously-rejected model in this case, PGE failed to do so.

- At the beginning of this case, the parties agreed to five rounds of testimony, which ostensibly would allow staff and intervenors two opportunities to address PGE's case in support of its requested rate increase. In support of its cost of equity (COE) estimate in its direct testimony, PGE relied on the testimony of two company witnesses. These witnesses arrived at their COE estimate by applying a Discounted Cash Flow (DCF) model to three different sample groups and by applying the risk-positioning model. In its rebuttal testimony, PGE offered the testimony of another COE witness who testified regarding COE results obtained with other financial models. Staff and other parties had only one round of testimony in which to discuss these models.

- In sursurrebuttal testimony, PGE decreased its cost of debt estimate based on its determination that it would issue $300 million of debt in 2007, rather than the amount assumed for its direct and rebuttal testimony. Given the timing of PGE's disclosure regarding the $300 million debt issuance, neither staff nor intervenors are given the opportunity to testify regarding the appropriateness of PGE's re-calculated cost of debt.

For the most part, PGE's failure to meaningfully address issues and criticisms raised by other parties merely hurts PGE's case. This is because PGE bears the burden of persuasion in this case. However, in some instances, PGE's failure prejudices other parties. Specifically, PGE's last-minute adjustment to its cost of debt estimate and proposal for a deadband prejudice other parties because they have no opportunity to testify on these issues. While staff is able to respond to PGE's modification to its cost of debt estimate in this brief, it is not able to respond to PGE's deadband proposal. Accordingly, staff asks the Commission to ignore it.

As discussed in the pre-hearing brief, many of the issues presented in these consolidated dockets have been resolved by stipulation. The issues for which there is no agreement between the parties concern four adjustments related to PGE's forecast of net variable power costs ("NVPC"), the model PGE uses to forecast NVPC, two power cost adjustment mechanisms for which PGE seeks approval, PGE's cost of equity (COE), cost of debt and capital structure, the prudence of PGE's new generating facility, Port Westward, and other issues raised by the City of Portland and the Eugene Water and Electric Board ("EWEB"). Staff discusses all but the issue regarding Port Westward and the issues raised by the City of Portland and EWEB below.

II. Argument.

a. Power costs.

Staff recommends that the Commission make four adjustments to PGE's proposed NVPC for the forced outage rates for PGE's Boardman and Colstrip plants, the sale of ancillary services, and the extrinsic value of PGE's flexible resources.

1. Forced Outage Rate for Boardman and Colstrip Plants

To determine test period power costs for ratemaking, the Commission uses a "forced outage rate" to determine normalized generating unit availability. A forced outage is an unplanned failure of a generating unit. The forced outage rate is the proportion of forced outage hours to total hours a unit is capable of providing service on an annual basis. The Commission uses forced outage rates to reflect normal generating unit availability in its determination of test period power costs.[3] Since 1984, the Commission has generally used a four-year rolling average of actual unit forced outage rates to determine a unit's normal forced outage rate.

Staff recommends that the Commission abandon its practice of using actual forced outage rates to determine the forced outage rate for PGE's Boardman and Colstrip plants. Using actual forced outage rates gives too much weight to extreme events, resulting in unrealistic forced outage rates. Staff recommends that the Commission determine "normal" forced outage rates based on industry-wide averages from the North American Electric Reliability Council ("NERC").

PGE's opposition to staff's proposal has little substance. First, PGE argues that staff did not demonstrate that using NERC peer group averages would be less volatile than using the four-year average methodology.[4] Volatility of the four-year average is not a concern. Inappropriate weighting of extreme outage events is a concern, and is addressed by staff's proposal to use NERC data.[5]

Next, PGE argues that staff's proposal to use NERC data is inappropriate because staff does not apply the NERC-data methodology to PGE's other generating plants. Unlike the Colstrip and Boardman plants, PGE's other generating units did not experience any extraordinarily-long outages between 2002 and 2005. Accordingly, it is not necessary to use the NERC-data methodology to ensure against an unreasonably high forced rate for plants other than Boardman and Colstrip.

PGE also argues that the using the NERC industry-wide averages is inappropriate because NERC believes that a standard peer group for an adjustment such as that recommended by staff is more optimal if obtained through NERC's benchmarking services, rather than from NERC's reported peer group equivalent forced outage rates.[6]

[3] Staff/100, Galbraith/4.
[4] PGE/1900, Tinker-Schue-Drennan/41.
[5] Staff/1500, Galbraith/18.
[6] PGE/1900, Tinker-Schue-Drennan/42-43.

The information relied on by PGE for this argument does not show whether using a peer group selected through NERC's benchmarking services might benefit PGE or its customers. Even if it is assumed, however, that an adjustment that is more perfect than staff's proposed adjustment may be obtained by purchasing certain services from NERC, staff's proposed methodology for calculating the forced outage rates for PGE's Boardman and Colstrip plants is still superior to continuing to use the traditional methodology as PGE recommends.

Finally, PGE argues that it is inappropriate to use the NERC data to calculate the forced outage rate because it is not verifiable.[7] Staff disagrees with PGE's assertion that the data is not verifiable.

2. Ancillary Services

Ancillary services are defined by NERC as services necessary to support the transmission of capacity and energy from the resources to the loads while maintaining reliable operation of the provider's transmission system in accordance with good utility practice.[8] PGE began selling ancillary services in January 2005 and includes the costs of ancillary service sales in its 2007 test year NVPC, but not the corresponding revenues.[9] Staff recommends correcting this mismatch by including ancillary service sales revenues in the 2007 test year revenue requirement, as well as the costs.

PGE's opposes staff's recommendation, arguing that the Commission should address the mismatch identified by staff through a comprehensive variance tariff because (1) there is "considerable risk to making a revenue projection for the test year," and (2) staff's recommended adjustment does not take into account certain offsetting costs, namely grid management costs, and thus is overstated.[10] PGE's arguments are meritless.

[7] PGE/100, Tinker-Schue-Drennan/44.
[8] Staff/200, Wordley/2.
[9] Staff/202, Wordley/1
[10] PGE/1900, Tinker-Schue-Drennan/47-48.

First, to the extent PGE asserts that the adjustment is incorrect because it does not include certain costs, it is incumbent on PGE to provide evidence supporting this assertion. Instead, PGE merely asserts the adjustment is overstated and asks the Commission to reject it. In absence of persuasive evidence showing that staff's adjustment is overstated, the Commission should reject PGE's assertion that it is.

Second, PGE's recommendation to the Commission to ignore the mismatch of costs and benefits in this proceeding and assume it will be resolved through a future variance tariff filing is not a solution. The existence of a variance tariff, if the Commission ultimately approves such a mechanism, is irrelevant with regard to this adjustment, which establishes a consistency between ancillary services revenue and costs in the company's revenue requirement. There is no valid reason to delay the correction that staff suggests. The Commission should address the inequity that currently exists in PGE's rates by adopting staff's proposed adjustment.

3. Extrinsic value and stochastic modeling.

Extrinsic value is the dollar value produced by the flexibility of a power resource to operate profitably in a wholesale power market characterized by volatile and correlated natural gas and electricity prices. This flexibility is also called optionality. The value of this optionality is realized through profitable opportunities that present themselves with economic dispatch of the company's flexible resources in the uncertain market. Although PGE has acknowledged the extrinsic value of its resources in its IRP and RFP evaluations, PGE does not include this value in its forecasted NVPC.

Resources not used to full capacity in a forecasted period have extrinsic value. For the 2007 test year in this case, two of PGE's power plants and three purchase power contracts have unused capacity. To estimate the extrinsic value of the two power plants and one of the contracts, staff used estimates of extrinsic value PGE developed for the evaluation of alternative bids in response to the company's 2004 RFP for resource capacity. The remaining two power purchase contracts were evaluated in the RFP. Accordingly, staff used PGE's extrinsic value estimates for those contracts.[11]

Staff's extrinsic value adjustment is related to its recommendation regarding stochastic modeling. Stochastic modeling would allow PGE to model, for the purpose of forecasting NVPC, the optionality of its resources. Stochastic modeling would capture uncertainty associated with, and interaction of not only electricity and natural gas market prices, but also system loads, hydroelectric generation and thermal unit availability, and therefore provide a more realistic simulation of PGE's actual power system operations. If PGE used stochastic modeling, the Commission would not need to make an extrinsic value adjustment.

Given the relationship between staff's recommendations regarding extrinsic value and stochastic modeling, as well as PGE's concern that the cost to serve customers will not be the same as the costs implicit in rates (what PGE refers to as "cost of service risk"), PGE's responses to these recommendations are puzzling. PGE acknowledges the infirmities of its current modeling, admitting: (1) "Our NVPC forecast does not reflect [extrinsic value] because it models only a point electric power market and gas market price"; (2) "retail customers' demand for power will rise significantly above [the] forecast" used in MONET; (3) "any one or more of PGE's resources can experience difficulties at any time" that are not modeled in MONET; and (4)"[capacity resources] are available for events that we anticipate but cannot precisely forecast."[12] Notwithstanding that PGE acknowledges the infirmities of MONET and is concerned with what it calls "cost of service" risk, PGE still opposes changes to modeling methodology that will address uncertainty and result in a better match of forecasted costs to actual costs.

[11] Staff/200, Wordley/11-12.
[12] PGE/1900, Tinker-Schue-Drennan/22-23.

PGE's response to staff's extrinsic value adjustment is similar to its response to staff's ancillary services adjustment. PGE acknowledges the infirmity identified by staff – its resources have extrinsic value that is not captured in rates – but argues that the Commission should reject staff's adjustment because staff did not consider other potential costs associated with uncertainty when recommending its adjustment. PGE argues that because the adjustment only captures a portion of the impacts that uncertainty may have on the company's NVPC forecast, the Commission should reject the adjustment.

PGE's recommendation is inappropriate. If PGE believes the adjustment is incorrect because it fails to include all impacts of uncertainty on PGE's NVPC, it is incumbent on PGE to provide persuasive evidence demonstrating what an adjustment with all impacts would be. Instead, PGE expects the Commission to simply accept PGE's assertion that the adjustment is deficient and reject it, even if it means ignoring the infirmity in PGE's NVPC forecast with respect to the value of certain resources.

In any event, PGE's argument that staff's adjustment amounts to "cherry-picking" is unfounded. Staff's adjustment focuses on a subset of PGE's resources for which PGE has the option, depending on market conditions, to use or not use to make a positive margin and which have unused capacity in the test year. That this optionality has value, and that this value is quantifiable, are not disputed.

PGE's other resources do not require an extrinsic value adjustment. ICNU witness, Randy Falkenberg, explained why ICNU's extrinsic value adjustment did not include coal or hydro resources:

> **Q. YOUR ANALYSIS DOES NOT INCLUDE COAL OR HYDRO PLANTS. PLEASE EXPLAIN.**
>
> A. For plants with very large spreads, whether positive or negative, the expected value of savings will be zero. For example, a coal plant might have a spread of -$30/MWh, and the standard deviation of the spread is $5/MWh. It would take a very extreme event before the unit would be "out of the money."[] In such cases, the expected value of the

difference between the spread in the probability distribution and the Monet spread is zero, resulting in no additional savings. Calculations provided in my workpapers show scenarios where the spreads are very large (both positive and negative) resulting in no extrinsic value. This confirms the reasonableness of the method employed and demonstrates that to capture the benefits of stochastic price modeling, it is not necessary to model all plants on the system. Only the "marginal" plants are likely to have spreads close enough to zero to make this kind of analysis necessary or useful.

Q. YOUR METHODOLGY MIGHT BE CRITICIZED ON THE BASIS THAT IT ONLY TREATS GAS AND MARKET ELECTRIC PRICES AS STOCHASTIC VARIABLES, WHILE OTHER VARIABLES ARE DETERMINISTIC. PLEASE COMMENT.

A. One could consider including a host of stochastic variables: loads, outage rates, coal prices, and hydro generation in addition to gas and power prices. However, in at least some cases, it is unlikely the expected value of the power cost distribution would change, though the dispersion probably would. For example, coal prices are not known in advance. If one accepts the forecasted coal price as an unbiased mean, it is unlikely that uncertainty surrounding coal prices will be responsible for a systemic under or overstatement. Coal prices for individual plants are unlikely to have systemic effect on market prices because coal is seldom at the margin. As a result, there is no reason to believe that inclusion of other variables in a stochastic analysis would change the expected value of power costs.

Certainly, it is likely that load and hydro conditions would affect market prices, though probably not as much as gas prices. However, loads will be unlikely to have substantial impact unless all utilities in the market experience correlated load variations. There is some debate as to the impact of hydro variations on market prices as well. By using historical data over a four-year period, certainly some variations in load and hydro condition have been captured in the price spreads used in my model. In the end, models improve when the capability and desire to improve them exists. By adopting a stochastic price adjustment, the Commission could well provide the impetus for the utilities to improve their models.[13]

PGE's arguments regarding the mechanics of staff's adjustments also have little substance. PGE argues that the estimate of extrinsic value it used to make capacity resource decisions (on which staff based its adjustment) is not a forecast and accordingly, cannot be used for ratemaking. PGE argues that ratemaking requires "prohibitive precision" while resource planning does not. These arguments are meritless. First, to the

[13] ICNU/103, Falkenberg/8 (footnote omitted).

extent the utility relies on extrinsic value estimates to make multi-million long-term investments in resources, the estimates should be sufficient to determine test year costs for rate-making purposes. Second, as PGE admits, its current power cost methodology is flawed. It is therefore disingenuous to suggest the extrinsic value estimates PGE developed for IRP/RFP should not be used for ratemaking because they were based on less than precise modeling.

Staff's extrinsic value adjustment is intended to improve PGE's power cost estimation methodology. Staff recommends that the Commission indicate a preference for stochastic power cost modeling to incent the company to develop such a methodology. However, until the company develops and implements stochastic power cost modeling, staff's extrinsic value adjustment improves the company's current NVPC estimate by ensuring customers receive the benefits from the company's flexible power resources for which they are paying in rates.

b. PGE's proposed Annual Update and Annual Variance Mechanisms.

PGE asks the Commission to authorize two power cost mechanisms that shift to customers risk for variations in NVPC that has traditionally been borne by the utility. PGE's proposals not only depart from traditional ratemaking, but from a policy that is clearly discernable from Commission orders issued since 2001, which is that utilities absorb variations in NVPC that represent normal business variability or risk. PGE's proposed Annual Variance Mechanism is also inconsistent with the Commission's primary design criteria for a power cost mechanism announced in Docket Nos. UE 165/UM 1187. Although the Commission described the design criteria for a hydro-only power cost mechanism, there is no reason these criteria should not apply to a comprehensive power cost mechanism. Accordingly, if the Commission decides to adopt the power cost mechanisms proposed by PGE, the Commission must be willing to shift to customers risk that has traditionally been borne by the utility and revisit the orders it issued in Docket Nos. UE 165/UM 1187, UM 995 and UM 1071. Staff recommends that the Commission do neither.

1. Utilities bear risk for normal business variability between rate cases.

The policy referred to above is clarified in Commission orders in Docket Nos. UM 995, UM 1071 and UE 165/UM 1187. In Docket No. UM 995, the Commission authorized PacifiCorp to defer extraordinary excess NVPC, for later inclusion in rates, subject to a sharing mechanism. The sharing mechanism had a deadband of +/- 250 basis points of PacifiCorp's ROE. The Commission found as fact that the purpose of the deadband was "to capture normal business variability to which the company is generally exposed between rate cases."[14]

Approximately three years later, the Commission denied PGE's request to defer excess NVPC related to poor hydro conditions, finding that the costs at issue, which equaled approximately 172 basis points of PGE's ROE, were not sufficiently significant to warrant deferral. The Commission noted that the costs at issue were well below those in Docket No. UM 995, in which the Commission had declined to allow recovery of NVPC less than 250 basis points of PacifiCorp's ROE:

> In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of utility business.[15]

Less than two years after its order in UM 1071, the Commission addressed PGE's request to recover excess NVPC in Docket No. UE 165/UM1187, in which PGE asked the Commission to authorize a power cost adjustment mechanism for NVPC variability

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[14] Order No. 01-420 at 6 and 29 (Commission specifically adopting statements by Commission Staff, including the statement quoted above).

[15] Order No. 04-108 at 9 (Docket No. UM 1071).

related to hydro conditions. Staff and PGE stipulated to a proposed power-cost adjustment mechanism in those consolidated dockets (the "SD-PCAM"), which would have allowed PGE to defer certain NVPC for later recovery, or refund, subject to an asymmetric deadband of + $15 million and - $7.5 million, 80/20 sharing outside the deadband, and an annual earnings test that would serve as both a ceiling and floor on PGE's recovery.[16]

In reviewing the SD-PCAM, the Commission specified four primary design criteria for a hydro-related PCA: (1) limited to unusual events; (2) no adjustments if overall earnings are reasonable; (3) revenue neutrality; and (4) long-term operation. The Commission rejected the SD-PCAM agreed to by staff and PGE because it did not meet the second, third, and fourth criteria. The Commission did conclude, however, that the SD-PCAM met the first criteria, "limited to unusual events" because it included a deadband of + $12 million and - $7.5 million.

PGE has articulated no sound reason for the Commission to depart from its previous conclusions regarding NVPC risk and design of PCA mechanisms. Staff recommends that the Commission decline to reject its previous conclusions regarding utilities' assumption of normal business variability risk, as well the primary design criteria for hydro-related PCA it articulated in Docket Nos. UE 165/UM 1187.

2. PGE does not explain why the Commission's policy should not apply in this docket.

As a preliminary matter, staff notes that *meaningful* discussion regarding the applicability of the Commission's policy regarding allocation of NVPC associated with normal business variability between rate cases is absent from PGE's testimony regarding its proposed power cost adjustment mechanisms. PGE's primary litigation strategy has been to deny the existence of the Commission's policy requiring utilities to absorb NVPC

[16] Order No. 05-1261.

associated with normal business variability risk between rate cases.[17] It is not until PGE's sursurrebuttal testimony that PGE acknowledges that recent Commission orders may reveal "the recent direction of Commission policy" to limit a utility's recovery of NVPC, between rate cases, to costs those that are unusual or extraordinary.[18]

Due to the timing of PGE's change in litigation strategy, no party had opportunity to respond to the arguments PGE makes regarding the Commission's policy in its sursurrebuttal testimony. Staff will do so later in this brief. First, however, staff will describe PGE's proposed Annual Variance Mechanism in more detail and discuss its infirmities.

3. The Commission should reject PGE's Annual Variance Mechanism.

PGE asks the Commission to authorize an "Annual Update Mechanism" and an "Annual Variance Mechanism." The Annual Update Mechanism is a prospective automatic adjustment clause that would forecast normalized NVPC each year. The Annual Variance Mechanism would track differences between actual NVPC and the NVPC reflected in its rates through the Annual Update mechanism, and allocate 90% of that difference to customers. Specifically, the Annual Variance mechanism would:

- Track the difference between actual unit NVPC and the unit NVPC reflected in rates;[19]
- Determine the Annual Variance by multiplying the difference between unit NVPC by the actual loads from the variance period;
- Place ninety percent of the Annual Variance in a balancing account for later offset or amortization;
- Employ an earnings test prior to amortization of any deferred amounts; and

[17] *See e.g.*, PGE/400, Lesh/43-44 (witness stating that she is not aware of any regulatory policy reason for applying a deadband).

[18] PGE/2400, Lesh/11.

[19] Unit NVPC is defined as NVPC divided by loads (i.e., NVPC per KWh).

- Share with customers fifty percent of any earnings exceeding an updated return on equity (ROE) by more than 100 basis points.[20]

PGE's proposed Annual Variance Mechanism is inconsistent with the Commission policy discussed above, which is encapsulated in the Commission first primary design criteria identified for a hydro PCA. That policy is that utilities shall maintain risk of normal business variability between rate cases. The design criteria is that the PCA will be "limited to unusual events."

PGE attempts to justify its departure from the Commission's policy and first primary design criteria by re-defining the risk a power cost mechanism is intended to address. PGE asserts that the risk addressed by a power cost mechanism is "cost-of-service" risk, which is the risk that "cost of service prices charged for PGE's on-demand retail electricity service will not reflect actual cost of service."[21] Accordingly to PGE, increases in power costs are PGE's risk, and decreases in power costs are customers' risk.[22] PGE's attempt to guide the Commission's decision regarding its proposed mechanism by redefining the risk at issue is unavailing for the following reasons.

First, to prevail on the issues presented by its Annual Variance Mechanism proposal, PGE must demonstrate why the Commission's policy regarding allocation of risk between rate cases and design criteria are no longer reasonable. PGE's insistence that the pertinent risk addressed by a power cost mechanism is "cost-of-service" risk is not sufficient for this purpose.

This is particularly true in light of the Commission orders discussed above, as well as staff testimony, which make clear that the risk appropriately addressed by a power cost adjustment mechanism is the risk of extreme, or at least unusual, variations in NVPC. In Order No. 05-1261, the Commission stated, "[a] hydro-related PCA should be designed so that recovery or refund occurs only if the hydro event is unusual."[23] Staff

[20] Staff/800, Galbraith 5.
[21] PGE/1800, Lesh/7.
[22] PGE/2400, Lesh/19 at footnote 2.
[23] Order No. 05-1261 at 9.

witness Galbraith reiterates the Commission's conclusion, testifying in this case, as it has in previous cases, that "PCA mechanisms should be used to protect the company from extreme fluctuations in NVPC."[24]

Second, as explained in staff testimony, the Commission should consider the impact to customers when defining the risk addressed by the power cost adjustment mechanism. As already noted, PGE characterizes increases in power costs as PGE's risk, and decreases in power costs as customers' risk. This characterization is incomplete and misleading.

Staff has analyzed differences between actual and forecasted power costs from the perspective of both the shareholder and customer.[25] From the shareholder perspective, without a PCA mechanism increases in power costs, all other things constant, result in decreased earnings. Without a PCA mechanism, PGE is at risk from increases in power costs. Decreases in power costs, all other things constant, result in increased earnings. The opportunity for reward goes hand-in-hand with the risk exposure.

What PGE characterizes as customers' side of cost-of-service risk is more accurately characterized as customer's potential reward from implementation of a PCA mechanism. However, a PCA mechanism not only provides customers with an opportunity to gain from decreases in power costs, it also exposes customers to rate increases associated with increases in power costs. PCA mechanisms do not reduce risk; they shift risk (and reward) from shareholders to customers.

More specifically, PGE's proposal shifts to customers 90% of the risk that actual NVPC will vary from the NVPC implicit in rates. Although customers may receive benefit from this shift, *i.e.,* when NVPC is lower than forecast, customers are generally better off without this risk. This is because: (1) customers likely assign more weight to

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[24] Staff/800, Galbraith/9.
[25] Staff/1500, Galbraith/3-9.

the avoidance of large rate increases then they do to the pursuit of rate decreases, and (2) PGE's exposure to higher NVPC is greater than its exposure to lesser NVPC.[26]

Furthermore, customers would not only bear risk for excess NVPC traditionally borne by utilities under PGE's proposal, they would bear increased risk. This is because PGE's mechanism reduces PGE's incentive to efficiently manage its operation, thereby increasing the risk of excess costs.[27]

Third, it is PGE that is most able to manage "cost-of-service risk," not customers. It is appropriate to leave risk of normal business variation with PGE, and shift to customers only risk for extreme or unusual costs.[28]

As noted above, PGE finally acknowledged in its sursurrebuttal testimony the Commission's current policy regarding allocation of NVPC risk between rate cases and presented arguments as to why that policy should not apply to any power cost mechanism adopted in this docket. Staff did not have opportunity to respond in testimony to these arguments, which are listed below, but will respond to them in this brief. Briefly, PGE argues that including a deadband in a power cost adjustment mechanism:

- Increases cost-of-service risk to both PGE and PGE's customers
- Is a significant departure from Oregon's prior policies with respect to electric utilities and current policies with respect to natural gas utilities
- Is a significant departure from how other states regulate utilities otherwise comparable to PGE and will reflect negatively on Oregon's regulatory climate and PGE in the national financial markets
- Is not fair with respect to the different types of costs within a utility's power costs, allowing customers to enjoy the benefits of low embedded fixed costs but shielding them from the full variable costs of the same resources
- Is not fair across utilities because it ignores how much a given electric utility has invested in generation
- Skews the regulatory framework for normal business risk
- May not produce reasonable results over a multiple year period
- If based on a distinction among "events," does not have a sound factual basis.[29]

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[26] Staff/1500, Galbraith/7-8 and PGE/1900, Tinker – Schue – Drennan/53.
[27] ICNU/103, Falkenberg/43.
[28] Staff/1500, Galbraith/11.
[29] PGE/2400, Lesh/13.

None of these arguments has merit.

A. PGE's argument that inclusion of a deadband in a power cost adjustment mechanism increases "cost-of-service" risk is illogical.

PGE's argument that approval of a PCA mechanism with a deadband increases "cost-of-service" risk is illogical. PGE compares regulation with a PCA mechanism without a deadband to regulation with a PCA mechanism that includes a deadband and concludes that a deadband increases "cost-of-service" risk. The proper conclusion is that a PCA mechanism with a deadband does not reduce as much "cost-of-service" risk as a PCA mechanism without a deadband. All PCA mechanisms reduce "cost-of-service" risk when compared to regulation without any PCA mechanism. Staff testified that the appropriate baseline for evaluation of PCA mechanisms is regulation without any PCA mechanism.[30]

B. PGE's arguments regarding Commission-authorized PCA's in the 1980's and Purchased Gas Adjustment Mechanisms are not persuasive.

PGE argues that the Commission should not impose a PCA with a deadband because the Commission did not require a deadband for the comprehensive PCA the Commission authorized for PGE from 1979 to 1987. PGE's argument that the Commission should not impose a PCA with a deadband because it did not do so twenty years ago is simply not persuasive. Simply pointing out the type of mechanism the Commission employed in the late 1970's and early to mid 1980's does not offer insight on why the Commission's policies and design criteria articulated in recent orders is inappropriate.

PGE's reliance on Commission-authorized Purchased Gas Adjustments ("PGA") is not persuasive because the comparison between gas and electric utilities is not apt. As noted by witnesses for CUB, PGE is not a natural gas utility.[31]

[30] Staff/1500, Galbraith/5 and PGE/ , Lesh/
[31] CUB/ , Jenks/Brown/ .

Lastly, PGE's assertion that the power cost deadband and the earnings test deadband serve the same purpose and are duplicative is not well founded. In its direct testimony, staff clearly articulated that these deadbands serve different purposes. The purpose of the power cost deadband is to exclude a reasonable range of normal variation from triggering the PCA mechanism.[32] The purpose of the earnings test deadband is to override any surcharges when the company's earnings are above the bottom of a reasonable range.[33]

C. PGE's argument that a deadband is a significant departure from how other states regulate utilities otherwise comparable to PGE is not persuasive. PGE's argument that a deadband will reflect negatively on Oregon's regulatory climate and PGE in the national financial markets is not supported by credible evidence.

PGE's argument that a PCA with a deadband is a significant departure from how other states regulate utilities is not, to staff's knowledge, the type of argument this Commission has ever found to be persuasive.

PGE's argument that a PCA with a deadband "will reflect negatively on Oregon's regulatory climate and PGE in the national financial markets[,]" is not supported by credible evidence. PGE relies on a September 25, 2006, S&P Research Report on PGE. Ms. Lesh testifies:

> Recently, S&P[] changed its outlook on PGE to 'negative' and cited "an uncertain regulatory environment," and "power cost variations that cannot currently be passed through to customers" as concerns. S&P also stated that it could PGE's outlook to stable if, among other items, "a sufficiently supportive PCA mechanism is adopted in addition to extension of the RVM."[34]

[Confidential material begins]

[32] Staff/800, Galbraith/9.
[33] Staff/800, Galbraith/17.
[34] PGE/2400, Lesh/16 (footnote omitted.)

[Confidential material ends]

In sum, it is impossible to conclude that S&P conducted a timely independent inquiry into the powercost frameworks proposed by the parties in this proceeding, let alone whether S&P has an opinion on whether a PCA with a deadband is "sufficiently supportive."

D. PGE's argument that a deadband shields customers from paying the full variable costs of resources is not well founded.

The Commission determines the full fixed costs of PGE's resources in a general rate case. The Commission also determines the full variable costs of PGE's resources when it determines normalized NVPC in a general rate case. As a result, PGE recovers the full cost of its resources in base rates. PGE challenges this logic by implicitly equating full variable costs with actual variable costs and then suggesting that a PCA mechanism without a deadband is necessary for the recovery of its actual costs. Contrary to PGE's assertion, a PCA mechanism with a deadband does not shield customers from paying the full cost of the company's resources.

E. PGE's argument that a deadband is not fair across utilities because it ignores how much a given electric utility has invested in generation is unpersuasive.

The ability of a utility to absorb increased power costs depends on its overall ratebase not its generation ratebase. Contrary to PGE's assertion, a policy that sets PCA mechanism deadbands proportional to overall ratebase treats utilities equally.

In any case, staff is not recommending a universal deadband that would be applied to all of Oregon's investor-owned electric utilities. Staff has indicated that the purpose of a deadband is to exclude a reasonable range of normal variation in power costs from triggering the PCA mechanism. This standard may result in different deadband recommendations for the different electric utilities.

F. PGE's argument that a deadband skews the regulatory framework for normal business risk is misguided.

In a nutshell, PGE's argument is that it cannot offset large increases in NVPC with reductions in non-power O&M. First, staff's proposed PCA mechanism does provide for recovery of large increases in NVPC. Second, the ability to offset cost increases is not the appropriate consideration. Staff and the Commission have both indicated the appropriate consideration is the ability of the utility to absorb costs between rate cases.

G. PGE's argument that a deadband may not produce reasonable results over a multiple year period is unpersuasive.

PGE's assertions about what history tells, and does not tell, about the future are unpersuasive. The issue is the likelihood and treatment of consecutive years of bad events. PGE seems to believe that a cap on the amount the utility is required to absorb over consecutive years would be appropriate, but stops short of making this part of its alternative deadband recommendation. PGE's discussion of this issue is untimely.

H. PGE's argument that a deadband does not have a sound factual basis is invalid.

PGE's assertion that "unusual" is "in the eye of the beholder" is about as effective as asserting that "cold" is "in the eye of the beholder". Asserting that the determination of "unusual" or "cold" requires judgment, does not imply that the determination is made without a sound factual basis. In Oregon, an outside temperature of minus 10 degrees Fahrenheit is cold, and unusual, in the eye of any reasonable beholder. Staff's recommended deadband is based on professional judgment (*see* UM 995) and compares favorably with alternative deadbands based on a simulated distribution of PGE's NVPC.[35]

In addition to including new arguments in its sursurrebuttal testimony, PGE included a proposal for a "NVPC variance deadband[,] in the event the "Commission

[35] Staff/1500, Galbraith/14-16.

believes one is necessary."[36] PGE's deadband proposal is untimely. No party has the opportunity to even investigate the merit of the proposal, let alone testify regarding its merit.

That the Commission may require inclusion of a deadband in any power cost adjustment mechanism it adopts should not have been a last-minute revelation for PGE. ICNU, CUB and staff all criticized PGE's proposed Annual Variance Mechanism quite sharply because it did not include a deadband and pointed out the Commission's orders that supported inclusion of a deadband. PGE chose not to respond to those criticisms in a timely manner. It should not be allowed to take advantage of that failure in its sursurrebuttal testimony.

4. PGE's Annual Variance Mechanism does not meet the Commission's second and third design criteria.

Notwithstanding PGE's failure to include a deadband in its Annual Variance Mechanism, and thus satisfy the Commission's first primary design criteria, the Commission should also reject PGE's Annual Variance Mechanism because PGE did not establish that its mechanism satisfies the second and third primary design criteria. The Commission's second primary design criteria is that the mechanism not allow adjustment for NVPC variability if the utility's overall earnings are reasonable. In UE 165/UM 1187, the Commission noted that a mechanism that would preclude recovery of excess NVPC if the utility's earnings otherwise were at least equal to the bottom of a range around the utility's ROE would meet this criteria.[37]

While PGE's proposed mechanism does include an earnings test, it is decidedly different than that described by the Commission in Order No. 05-1261. Whereas the Commission described a mechanism in which the utility would not recover excess NVPC if its earnings exceeded a range below the utility's ROE, PGE proposes that it be allowed

[36] PGE/2400, Lesh/21.
[37] Order No. 05-1261 at 9-10.

to recover any NVPC variation unless its earnings exceed an amount equal to 100 basis points *above* PGE's ROE, which would be re-set each year. PGE's proposal would essentially guarantee PGE the opportunity to earn over its rate of return. This proposal does not satisfy the Commission's second design criteria.

With respect to whether PGE's Annual Variance Mechanism meets the Commission's third primary design criteria, little discussion is necessary. PGE acknowledges that it did not attempt to show that its proposed mechanism satisfies the Commission's third primary design criteria, revenue neutrality. [38]

5. The Commission should reject PGE's Annual Update Mechanism.

Staff also recommends that the Commission reject PGE's Annual Update mechanism. This mechanism would be cumbersome and time consuming and it is unclear whether its benefits would outweigh the regulatory burden it would impose. Notably, the mechanism is very similar to the current RVM. However, under PGE's proposal in this docket, staff and other intervenors would have three months less to examine PGE's filing and pursue discovery.[39]

Furthermore, under PGE's new method for determining the transition cost adjustment, an annual update mechanism is not necessary. It is also not necessary if the Commission adopts staff's proposed power cost adjustment mechanism that is described below.

6. Staff recommends the Commission adopt Staff's proposed PCA.

Staff's proposed Power Cost Adjustment ("PCA") mechanism satisfies the Commission's design criteria. Staff recommends a long-term retrospective PCA mechanism that would:

- Track the difference between the actual unit NVPC and the unit NVPC reflected in rates;

[38] PGE/400, Lesh-Niman/46.
[39] CUB/200, Jenks-Brown/13.

- Determine the annual variance amount by multiplying the difference between unit NVPC by the normalized loads reflected in rates;

- Use a power cost deadband equal to plus and minus 150 basis points of ROE to exclude normal variation from triggering the mechanism;

- Place ninety percent of all amounts exceeding the power cost deadband in a balancing account for later offset or amortization;

- Use an earnings test with a deadband equal to plus or minus 100 basis points of ROE to override any surcharges (surcredits) when the company's earnings are above (below) the bottom (top) of a reasonable range; and

- Apply any surcharges or surcredits to customers that were charged cost-of- service rates during the PCA year.

As already noted, the primary purpose of a PCA is to protect the utility from major increases in net variable power costs. Staff's proposed mechanism does this, and also incents the utility to minimize NVPC, does not incent direct access eligible customers on their choice to elect direct access or remain with the company and also, overrides any surcharges or surcredits triggered by large variability in NVPC if PGE's earnings are above or below a reasonable range.

c. Cost of capital.

Staff's recommends a 6.20 percent cost of debt and 9.4 cost of equity ("COE") based on a capital structure of 50 percent debt and 50 percent equity, for a 7.80 percent overall rate of return.

d. Cost of debt.

PGE agreed, as a condition of the Commission's approval of its 2005 request to re-distribute its stock to Enron's creditors, to not seek recovery of increases in its costs of capital due to Enron's ownership. Approximately 41 basis points of PGE's latest cost of debt estimate, which is 6.73 percent, are attributable to Enron-related costs. Staff recommends that the Commission remove Enron-related costs from PGE's cost of debt and correct several errors in PGE's cost of debt analysis, which results in a cost of debt estimate of 6.20 percent.

Staff's adjustments and corrections to PGE's cost of debt analysis are listed below. Specifically, staff:

- Recalculated the internal rate of return (IRR) because PGE's calculation appeared to be in error.
- Substituted the actual amount of a $100 million issuance PGE plans for mid-2007 for the average gross proceeds ($54 million), PGE used to calculate the IRR.
- Removed losses on reacquired debt.
- Re-priced PGE's pro forma debt issuance to reflect updated interest rates and spreads.
- Re-priced six issuances negatively affected by Enron's ownership of PGE.

In its sursurrebuttal testimony, PGE modified its already amended proposal for long-term cost of debt from 6.826 percent to 6.73 percent. This update did not include the corrections and Enron-related adjustments proposed by staff. Instead, PGE updated its cost of debt estimate because it concluded it would to issue $150 million more debt than it discussed in prior rounds of testimony and would issue a substantial amount of debt with a ten-year maturity. In light of the new information regarding PGE's planned debt issuances, staff modifies its cost of debt estimate to 6.20 percent.[40]

The major differences between staff's estimate of PGE's cost of debt and PGE's modified proposal is Enron-related costs that account for approximately 41 basis points. The remaining difference of 12 basis points is due to other corrections and standard adjustments that staff describes below. For example, when recalculating PGE's cost of

[40] Attachment A to this brief is a spreadsheet updating staff's analysis for the additional facts PGE provided in its sursurrebuttal testimony.

debt to include the new information regarding PGE's debt issuances, staff followed its long-standing practice of using the most current Treasury Rate, which was 4.565 percent on November 14, 2006.[41]

1. PGE's IRR calculation.

PGE finds staff's first correction to the IRR of each of PGE's debt issuances to be of little moment. PGE notes that the differences between staff's IRR calculations are small (approximately one-half basis point) and that it does not understand why staff believed it was important to discuss.[42]

PGE did not provide its workpapers showing its IRR calculations, so staff could not determine why there was a difference between its IRR calculations and those of the Company. However, staff was able to create the IRR calculations itself using Excel formulas. When staff determined the resulting IRRs did not match, Staff decided to report the discrepancy rather than ignore it or make the correction without mention. Staff described its correction to be sure the results were clear and reproducible.

2. PGE's use of "average gross proceeds" rather than actual cost of an anticipated 2007 issuance results in an inflated IRR and estimate of overall embedded cost of debt.

PGE's cost of debt includes a $100 million issue planned for sometime around July 2007. PGE did not use the full amount of the expected issuance to calculate its IRR, but used a "monthly average balance" of $54 million. In its calculation of the IRR, staff substituted the actual amount of the issuance for the monthly average balance used by PGE for two reasons. First, because PGE did not average the expected fees in a similar way, using the monthly average resulted in an inflated IRR. Second, because the

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[41] Attachment B to this brief is a spreadsheet showing the treasury rate on November 14, 2006. Staff asks the Commission to take official notice of the November 14, 2006 treasury rate under OAR 860-014-0050. *See* OPUC Order No. 99-697 at 20 (Commission taking official notice of spot rates for five-, seven-, and ten-year U.S. Treasury securities).

[42] PGE/2000, Hager-Valach/11.

assumed debt in 2007 is less expensive than PGE's embedded cost of debt, assuming a lower balance inflated PGE's estimate of its embedded cost of debt.[43]

PGE argues that its use of the monthly average balance is consistent with how it treats its outstanding debt.[44] This argument is without merit. For example, when assuming the replacement of existing long-term debt that is maturing within the test period, staff does not argued to average the few months of the old debt series with the remaining months of the new debt series. Artificially lowering the outstanding amount of debt present at the end of the test period only serves to inflate the cost of debt on a going forward basis.

3. Staff properly assumed a ten-year maturity to price PGE's pro forma debt issuance.

PGE's complaint with staff's adjustment re-pricing PGE's pro-forma debt issuance anticipated in July 2007 appears to be limited to staff's decision to determine the price using a ten-year maturity. PGE argues that staff should have assumed a thirty-year maturity for the 2007 $100 million issue because this is what PGE intends to issue. PGE argues that by assuming a 10-year maturity, staff "is essentially setting a maturity schedule for future debt issuances."[45] Again, PGE's argument is not well taken.

First, it is important to put staff's use of a ten-year maturity into context. Staff uses the ten-year maturity term only to price debt that PGE says it plans to issue around July 2007. This maturity may or may not match the maturity of the debt PGE issues; much like the interest rate assumed for the debt may or may not match the actual interest rate of the actual issuance. The maturity assumption is a tool to estimate the cost of the anticipated debt issuance, not to limit PGE's flexibility in issuing the debt.

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[43] Staff/1200, Conway/3.
[44] PGE/2000, Hager-Valach/12.
[45] PGE/2000, Hager-Valach/12-13.

As explained by staff, if the Commission assumes a maturity for replacement debt that is too long, this increases the potential gains to shareholders at the expense of customers. This is because the Company can choose to issue debt of a shorter maturity, and incur interest expense that is lower than that implicit in rates. Assuming a ten-year maturity does not preclude PGE from issuing debt with a longer maturity. However, it does help ensure that PGE will not be able to obtain a windfall at the expense of customers.

Furthermore, PGE's assertion that staff did not "take into account PGE's need to stagger its maturity dates as part of an overall financing strategy" is factually incorrect. In support of this assertion, PGE apparently relies on the following exchange during PGE's deposition of staff witness Conway:

> [PGE counsel:] Would you expect that the Company – one of the considerations that they have when they issue debt is to stagger the maturity of the various debt issuances so that they do not all mature at the same time?
>
> [Conway:] Yes, that would be a reasonable thing for them to do.
>
> [PGE counsel:] And did you take that into account when you recommended that the maturity be based on a 10-year rate?
>
> [Conway:] I looked at the maturing – maturities going forward, but I didn't provide an exhibit that showed all the maturities that would be coming due over the next 10 to 20 years.
>
> [PGE counsel:] And in looking and performing that analysis, did you conclude that a maturity in 10 years would be a reasonable thing to do?
>
> [Conway:] No, actually what I – what I advocated for, was a – it was more – it was standard; it wasn't saying you must issue it with a 10-year. * * * [46]

[46] PGE/2021, Hager-Valach/2.

PGE's reliance on Mr. Conway's deposition testimony is misplaced. Mr. Conway did not state that "staff did not take into account PGE's need to stagger its maturity dates as part of an overall financing strategy." In fact, the opposite is true. Mr. Conway stated that he did look at maturities going forward, but did not provide an exhibit that showed all the maturities that would be coming due over the next 10 to 20 years.[47] Furthermore, the full exchange between Conway and PGE counsel on this topic elucidates staff's reasoning underlying its use of an assumed ten-year maturity. A few minutes after the exchange set forth above, Mr. Conway explains:

> What I'm testifying to is that the Company has not issued the debt. It is unclear what term they will use. When I refer to an average maturity of 10 years, it is not a specific 10-year point in time. They could issue it shorter, they could issue it longer.[48]

Additionally, PGE's argument that assuming a ten-year maturity for its 2007 issuance will not allow it to recover its costs if the issuance actually has a thirty-year maturity is not persuasive. As Mr. Conway noted in his deposition, his ten-year maturity is based on a Treasury rate as of August 17, 2006, and a spread produced by PGE in response to a data request. It is probable that both the spread and Treasury rate will be different on the day that PGE actually issues the debt.[49]

Finally, PGE testified in its final round of testimony that it now plans to issue $150 million of 10-year first mortgage bonds during the test year.[50]

4. Staff properly excluded losses on reacquired debt.

Staff properly excluded losses on reacquired debt from the cost of long-term debt. First, the debt securities are no longer outstanding and no replacement debt has been identified. Second, the expenses are non-recurring in nature. Accordingly, it is

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[47] PGE/2021, Hager-Valach/2.
[48] PGE/3103, Depo Tr/21.
[49] PGE/3103 Depo Tr/21-23.
[50] PGE/2700, Hager-Valach/4.

inappropriate to include them in rates going forward unless PGE can establish customers obtained some benefit that should be accounted for in future rates. Because PGE did not show that customers benefited from the early redemption, it is not appropriate to continue to charge customers for the debt.

The losses at issue are very similar to unamortized expense that the Commission excluded by from the cost of debt calculation in Docket No. UE 116. In that docket, which was a general rate case, the Commission excluded the unamortized expense associated with PacifiCorp's Quarterly Income Debt Securities (QUIDs) because the securities were no longer outstanding and PaciCorp had not replaced them with new debt, they were not recurring and also, PacifiCorp did not show how early redemption of the securities benefited customers. The Commission's conclusion regarding the QUIDS is as follows:

> In reviewing the record, we note that Staff consistently asked PacifiCorp to show the benefits the customers received when it redeemed the QUIDS in November 2000. Although PacifiCorp did show that the cost of debt fell, this was paid for by an increase in equity. Equity is more expensive than debt. While customers may have benefited from the redemption of the QUIDS, PacifiCorp has not shown us any actual benefits to customers from its actions. Therefore, these costs should not be put into rates.
>
> We understand PacifiCorp's contention that these costs should be allowed. Under usual circumstances, the issuance costs would roll forward into the new debt instrument. In this case, no new debt was incurred. If the Commission had been given persuasive evidence as to how customers specifically benefited from PacifiCorp's decision to redeem the QUIDS, we would be inclined to allow the expense. However, the mere fact that the cost of debt costs fell does not establish that the overall cost of capital also fell. Further, as the expense is non-recurring, it is not appropriate for it to be recovered as some other type of expense.[51]

PGE argues that the Commission's acceptance of staff's recommendation to exclude the reacquired debt costs would result in utilities being disinclined to redeem

[51] Order No. 01-787 at 19.

debt when it is cost-effective to do so unless they are also able to issue long-term debt at the same time. PGE's response misconstrues staff's testimony. In his deposition, Mr. Conway explained to PGE that a cost effectiveness analysis need not be restricted to issuing long-term debt:

> The analysis would be that the cost, all things included, fees, transaction costs, everything else, and identifying the replacement debt, would be -- or replacement sources of funds -- would be lower cost than the -- if they had left the bond in --in [alone].[52]

PGE also argues that staff "is asking for a cost-effectiveness study that we performed over 18 years ago[,]" and that PGE does not keep such detailed financial analysis for such a historical period.[53] Again, PGE's argument is not persuasive. It is PGE's burden to prove its proposed rates are just and reasonable. PGE cannot shed itself of this burden by complaining that the necessary proof does not exist anymore. Notably, when PGE was faced with a similar problem regarding its risk positioning model, it chose to re-create its analysis.[54]

5. Staff properly re-priced six debt issuances negatively affected by Enron's ownership of PGE.

Staff re-priced six debt issuances issued between October 10, 2002 and August 4, 2003, to ensure that the impact of Enron's ownership on PGE's cost of debt is excluded from PGE's rates. Those debt issuances include the following:

1. $100 million 5.6675% Series issued October 28, 2002
2. $150 million 8.125% Series issued October 10, 2002
3. $50 million 5.279 Series issued April 8, 2003
4. $50 million 5.35% Series issued August 4, 2003
5. $50 million 6.75% Series issued August 4, 2003
6. $50 million 6.875% Series issued August 4, 2003

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[52] PGE/3031, Depo Tr/16.
[53] PGE/2000, Hager-Valach/13.

[54] PGE/2000, Hager-Valach/62, lines 3-14.

Staff made these adjustments pursuant to a condition to which PGE agreed at the time it asked for authority to redistribute its stock.[55] The condition states,

> 6. (a) PGE agrees not to seek recovery of increases in the allowed return on common equity and other costs of capital (i) due to Enron's ownership of PGE or (ii) caused by the ownership by the Reserve of 25% or more of PGE's outstanding common stock. These capital costs refer to the costs of capital used for purposes of rate setting, avoided cost calculations, affiliated interest transactions, least cost planning, and other regulatory purposes.
>
> (b) PGE agrees not to seek recovery of increases in PGE's revenue requirement that result from Enron's ownership of PGE.
>
> (c) In connection with Conditions 6(a)(i) and (6)(b), PGE shall not make any distribution to shareholders that would cause PGE's common equity capital to fall below the level specified in Condition 5 plus $40 million. PGE has agreed to maintain this additional $40 million during the pendency of PGE's next general rate case to assure PGE's financial capacity to absorb adjustment(s), if any, in PGE's revenue requirement resulting from Conditions 6(a)(i) and/or 6(b).
>
> (d) Condition 6(c) shall expire thirty (30) days after the PGE tariffs approved in PGE's next general rate case become effective, without regard to any appeal of the Commission's order approving such tariffs.

As a preliminary matter, staff clarifies the theory underlying the adjustments. Staff's adjustments are not, as PGE seems to suggest, based on the prudence or reasonableness of the issuances. Staff does not suggest that the issuances were imprudent or that the costs were unreasonably high, given PGE's predicament. The purpose of staff's adjustment is to remove from PGE's cost of debt costs due to Enron's ownership of PGE in accordance with condition no. 6 of Order No. 05-1250. For this reason, PGE's argument that staff concluded that the costs of at least some of the issuances were reasonable at the time PGE requested authority to make them is of little relevance.[56]

[55] OPUC Order No. 05-1250.

[56] PGE/2000, Hager-Valach/19.

Similarly, PGE's argument that the Commission should determine whether PGE's long-term debt costs are "prudent" by examining the debt issuances on a portfolio level, misses the mark. PGE's analysis compares its debt issuances to similarly rated issuances. Staff analysis looks at the debt costs that would have occurred if PGE had not suffered a rating downgrade due to Enron's ownership. Comparing the debt costs to similarly rated companies moots the impact of Enron on PGE's bond rating. If a student flunks 4th grade, you wouldn't consider them "successful" based on an analysis that shows their grades were similar to other students who flunked 4th grade.

A. The mechanics of staff's adjustments.

PGE issued three of the issuances that are subject to staff's Enron-related adjustment pursuant to Order No. 02-477, which states:

> [t]he interest rate spreads generally appear to be somewhat high, though given the financial pressures that the Company has faced since the Enron bankruptcy filing, such would be anticipated and are in line with recent Commission financing decisions.[57]

As explained in staff's testimony, the first and third issuances listed above ($100 million 5.6675% Series issued October 28, 2002 and $50 million 5.279% Series issued April 3, 2003), had high issuance costs because PGE insured the First Mortgage Bonds (FMBs) with Ambac.[58] The first issue had an issuance cost of over $12 million (12 percent) and the second had an issuance cost of over $4 million (8.4 percent). In comparison, PGE's most recent issues had issuance costs, on average, of 0.68 percent. [59]

To offset the Enron effect, staff re-priced the bonds assuming that PGE was A rated, as it was in November of 2001, before Enron filed for bankruptcy in December 2001. Staff assumed an all-in interest rate of 5.19% for both issuances.[60] Staff estimated

[57] Order No. 02-477.
[58] Staff/1200, Conway/15.

[59] Staff/1200, Conway 15-16.

[60] Staff/1200, Conway/8 and 15-16.

the 5.19% based on fees PGE paid for its next ten-year issuance, issued in 2003, and also, NW's Natural's projected spreads for January 2003.

The second issuance listed above is a $150 million 8.125% Series issued October 10, 2002. PGE redeemed this debt issuance using a make-whole premium under which PGE pays a premium intended to make the lender indifferent between re-marketing the bond at a lower rate and the interest the lender would receive from PGE. This premium was approximately $12.9 million. The two debt series to which PGE allocated this premium are the $175 million 6.31% series issued April 1, 2006, and the $100 million 6.26% issued April 1, 2006. To account for the Enron effect, staff removed the $12.9 million of amortized costs associated with the make-whole call.[61]

With respect to the three remaining debt series that PGE issued in August 2003, staff subtracted 27.5 basis points from each issuance to account for the Enron effect. Staff based this adjustment by comparing the cost of PGE's issuance to the cost of a ten-year debt PacifiCorp issued just one month later. PacifiCorp shared many characteristics with PGE during 2003, geographic market (Western US) and Oregon regulation. On November 21, 2001, PacifiCorp was rated A- by S&P (A3 by Moody's), in part due to the Western Energy Power Crisis, while PGE was rated A. In 2003, however, PacifiCorp was still rated A-, while PGE had fallen to BBB+. Meaning, notwithstanding the volatility of the market and other pressures in the months during and following the Western Power Crisis, PacifiCorp maintained its A- rating. However, PGE's rating, dropped significantly, from a rating that was superior to PacifiCorp's prior to the time Enron filed for bankruptcy, and lower several months later.[62]

B. The evidence supports staff's adjustments.

In support of its conclusion that the debt issuances discussed above were higher cost because of Enron's ownership of PGE, staff's testimony includes excerpts of several

[61] Staff/1200, Conway/17.
[62] Staff/1200, Conway/17-18.

Commission orders that demonstrate PGE was negatively affected by Enron. PGE spends little time attempting to argue why these orders issued in 2001 through 2003 are not persuasive evidence that Enron's ownership of PGE affected PGE's access to market during that time period. Instead, PGE notes only that the orders reflect that PGE was having difficulties apparently due to both the deterioration of the financial and wholesale electric power markets and Enron's bankruptcy, but that staff only focuses on the Enron bankruptcy as a cause for PGE's financing difficulties. PGE also argues that Enron's impact on PGE's access to capital markets was primarily limited to access to the short-term debt market in the Fall 2001 through Summer 2002 period.[63] PGE's arguments are without merit.

First, the PGE's contention that PGE only felt the Enron effect in the Fall 2001 through Summer 2002 is refuted by representations that PGE made in May 2003. In May 2003, the Commission approved PGE's application to secure its 364-day Revolving Line of Credit with up to $200 million of FMBs. The Commission's order approving the application notes that PGE represented that the need to use FMBs as security was "due in large part to economic pressures that face the Company resulting from Enron's bankruptcy filing[,]" and that it is unclear when that pressure would be reduced.[64] Further, in PGE's Form 10-K filed March 17, 2003, PGE states,

> PGE's secured and unsecured debt ratings continue to be investment grade from Moody's Investors Service ("Moody's) and Standard and Poor's ("S&P"), with Fitch Ratings ("Fitch") currently carrying a below investment grade rating on the Company. In their 2002 reviews of PGE ratings, credit agencies cited PGE's reduced financial flexibility resulting from its status as a subsidiary of an insolvent parent (Enron), a difficult capital market environment, and uncertainty regarding ongoing federal investigations into the Company's energy trading activities in the western U.S. power markets. Also cited in such reviews was the expectation that PGE would be sold, the significant credit enhancement and strengthened liquidity resulting from PGE's creation of a ring fence structure (described

[63] PGE/2000, Hager-Valach/15.
[64] Staff/1201, Conway/46.

> in the following paragraph), as well as the Company's fundamentally sound operations, healthy capitalization ratios, and levels of earnings and cash flows.

PGE's argument that staff's analysis overlooks the impact of deteriorating markets on PGE's ability to access the capital markets is incorrect for at least two reasons. First, a review of PGE's statements and representations in 2001, 2002 and 2003 reflect that PGE generally placed the lion's share of the blame on Enron for its diminished access to markets. Second, staff's adjustments are intended to reflect what PGE's debt costs would have been during the pertinent time period, absent the Enron impact, and therefore incorporate the difficult market conditions faced by all utilities during that time.

That PGE itself blamed Enron for its limited access to capital markets is seen by examining the Commission orders attached to staff's testimony. On August 14, 2001, PGE obtained Commission authority to issue and sell up to $250 million fixed mortgage bonds ("Bonds") and/or senior unsecured debt ("Debt"), subject to certain conditions.[65] One of the conditions limited the fixed interest spreads for the Bonds and Debt to a defined table of spreads. In October 2001, PGE asserted that due to changes in capital markets, the previously authorized spreads did not allow it access to the Bond or Debt markets. Statements made by PGE's chief financial officer at a December 10, 2001 Special Public Meeting, which are set forth below, make clear that the "changes" in markets necessitating the increase in the markets' reactions to events unfolding at Enron.

Soon after the Commission issued its October 31, 2001 order increasing the authorized rate spreads for the issuances authorized in UF 4179, PGE requested that they be increased again. PGE filed its application on December 5, 2001, and requested that the issue be taken up as soon as possible at a Special Public Meeting.[66] At the meeting,

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[65] OPUC Order No. 01-726; Docket No. UF 4179.
[66] The audio file from the December 10, 2001 Special Public Meeting can be found at http://apps.puc.state.or.us/agenda/audio/2006/exhibit/spm1202001.mp3

held on December 10, 2001, PGE's chief financial officer, Jim Piro, made clear that the need for the increased spreads was primarily due to Enron:

> [Chairman Hemmingway:] Do you perceive this difference to be entirely due to Enron problems or are there things endemic within PGE itself or the market for securities that caused this change?
>
> [Jim Piro:] Tough question because the markets are looking at lots of things but primarily I would say this is the result of the Enron situation. The markets' uncertainty around the bankruptcy and trying to understand kind of how we fit in the overall picture with Enron. We did issue an 8-k last week to try and clarify that to the market place. How we are situated relative to Enron. But clearly, as the market is trying to sort out what is going on with Enron that has had some effect on our credit rating as well as our cost of capital.

In June 2002, PGE requested authority to issue up to $300 million of First Mortgage Bonds to secure the Company's short term revolving credit facilities. The Commission's order approving the request incorporates the following language: "PGE's request is in response to the financial pressures placed on the Company as a result of the Enron bankruptcy proceedings."[67]

On September 21, 2001, PGE obtained authority to borrow up to $100 million from Enron. The Commission specified, however, that the interest rate had to be less than or equal to PGE's commercial paper rate on the date the loan issued.[68]

Subsequently, PGE asked that the Commission modify the restriction on the interest rate because it did not have access to the commercial paper market.[69] On July 26, 2002, the Commission issued an order authorizing PGE to issue and sell First Mortgage Bonds ("FMBs") not to exceed $300 million. In that order, the Commission noted that PGE had recently received authorization for a $250 million of FMBs but had

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[67] Order No. 02-384, App. A at 2.
[68] OPUC Order No. 01-838; UF 4182.
[69] OPUC Order No. 02-444, App A at 2 (Commission adopting staff's statement that "[c]ompany has represented that neither PGE nor Enron has access to the commercial paper market.")).

not been able to complete the authorized transaction, and that the current authorization was intended to address PGE's problem: "Order No. 02-292 was issued to provide the requested authority. To date, the Company has not been able to issue that Order. The current application is designed to offer more flexible terms while not discounting the potential for finalizing the prior transaction." Additionally, Order No. 02-477 states that "[t]he interest rate spreads generally appear to be somewhat high, though given the financial pressures that the Company has faced since the Enron bankruptcy filing, such would be anticipated[.]"

To the extent PGE relies on its issuance of the "Golden Share" to support its argument that Enron's ownership of PGE did not affect PGE's access to capital markets after the Summer of 2002, the reliance is misplaced. PGE asserts that "after PGE issued the "Golden Share" of preferred stock in September 2002, its access to the markets returned to normal."[70]

Statements made by PGE in its March 17, 2003 10-K report belie this assertion. In the report, PGE notes that rating agencies believed PGE to have reduced financial flexibility, in part resulting from its status as a subsidiary of an insolvent parent (Enron). PGE also notes, however, that the rating agencies believe the ring fencing provision (the Golden Share) is a positive development. These statements make clear that even though the rating agencies may have believed issuance of the Golden Share was a positive development, it was not a panacea:

> PGE's secured and unsecured debt ratings continue to be investment grade from both Moody's Investors Service (Moody's) and Standard and Poor's (S&P), with Fitch Ratings (Fitch) currently carrying a below investment grade rating on the Company. In their 2002 reviews of PGE ratings, credit agencies cited PGE's reduced financial flexibility resulting from its status as a subsidiary of an insolvent parent (Enron), a difficult capital market environment, and uncertainty regarding ongoing federal investigations into the Company's energy trading activities in the western U.S. power markets. Also cited in such reviews was the expectation that PGE would

[70] PGE/2000, Hager-Valach/15.

> be sold, the significant credit enhancement and strengthened liquidity resulting from PGE's creation of a ring fence structure (described in the following paragraph), as well as the Company's fundamentally sound operations, healthy capitalization ratios, and levels of earnings and cash flows.

Further, a Fitch rating release at the end of the summer of 2002 demonstrates that Fitch placed little emphasis on the golden share and alert bond holders of continued reduced financial flexibility and access to funding sources:

> Based upon the company's representations, substantive consolidation of PGE in the bankruptcy of Enron seems unlikely due to the separate operation of the utility under its own name, separate officers, maintenance of separate books and records, avoidance of commingling of cash and assets, and practices consistent with Oregon Public Utility Commission conditions in approving the acquisition of PGE by Enron. Since any attempt to consolidate PGE with Enron in bankruptcy is not likely to succeed, there is no apparent advantage to any creditors of Enron or Enron management to force PGE into bankruptcy. Thus, Fitch's ratings of PGE do not anticipate near-term bankruptcy of the utility, but do contemplate continued reduced financial flexibility, access to funding sources and potential exposure as a member of the Enron control group relating to tax and employee benefit liabilities and other contingencies.[71]

Finally, staff's adjustments to PGE's cost of long-term debt focused on August 2003, take into account the difficult financial conditions faced by all Western utilities by dropping NW Natural as the proxy and adopting PacifiCorp, a company who also was affected by the Western energy crisis. Staff chose to compare PGE to an "A-" rated company or PacifiCorp as the proxy company. Staff explained that PacifiCorp shared many characteristics with PGE during 2003, geographic market (Western US) and Oregon regulation. Staff also pointed out differences such as PGE's more equity-rich capital structure and PGE's parent, Enron. On November 29, 2001, PGE was rated "A" while PacifiCorp was rated A3 by Moody's (A- by S&P) in part due to the Western Energy Crisis. (See Moody's release regarding PacifiCorp attached as Staff/1201, Conway/52-53.) In 2003, PacifiCorp was still rated A-, but PGE had fallen to BBB+.

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[71] Staff/1201, Conway/48-49; PGE's response to Staff Data Request No. 60, Attachment 060-A pages 58-59.

Also, in September 2003, PacifiCorp issued 10-year debt with a coupon rate of 5.45 percent. In contrast, PGE's 10-year issuance from August 2003 was 5.625 percent, a difference of 0.175 percent. For purposes of calculating the Enron effect, staff assumes the 17.5 basis point difference between two Oregon utilities is due to PGE's relationship with Enron.

e. Cost of equity and capital structure.

In the last three rate cases in which cost of equity ("COE") has been litigated, the Commission has determined the COE by examining the integrity of the models used by the parties to estimate COE, as well the reasonableness of the models' results. PGE asks the Commission to supplement this analysis with ad hoc determinations regarding specific risks faced by PGE in Oregon and concomitant adjustments. PGE did not, however, explain to the Commission why it should depart from the analysis underlying its previous determinations of COE, in which no such determinations or adjustments were made. And, in any event, PGE did not demonstrate that the financial models used by the parties are so deficient that ad hoc determinations regarding PGE-specific risk are necessary in order to arrive at a reasonable COE for the company.

Additionally, PGE's witnesses appear to confuse the standard for setting the COE. Specifically, it appears they believe ROE for the Company and the actual COE for the equity investors are interchangeable terms. These two figures are not identical.

In the argument below, staff follows the analysis used by the Commission in Docket Nos. UE 115, UE 116, and UG 132, which is to examine the models used by the parties, and the results of those models. However, staff prefaces this discussion by identifying several infirmities and inconsistencies in PGE's COE testimony:

- In Order Nos. 01-777 and 01787, the Commission adopted guidelines for cost of equity witnesses, specifying that "[w]hen advocating a new approach, or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology in the present docket."[72] PGE urges the Commission to reject staff's COE recommendation because staff did not consider PGE-specific risk in estimating COE. The Commission has not previously made adjustments to a utility's COE based on utility-specific risks. Because PGE is advocating a new approach to determining COE, it was incumbent on PGE to explain why the Commission should adopt it. PGE failed to do so.

- Putting aside the fact that PGE failed to explain why the Commission should adopt a new analysis and make determinations and adjustments based on PGE-specific risk, PGE failed to quantify PGE-specific risk and failed to provide persuasive evidence demonstrating what effect PGE-specific risk should have on its COE.

- PGE's COE estimate is based in part on a "risk positioning model." In Order No. 01-787, the Commission stated that a similar model should not be used as a basis for a COE estimate, although it could be used to measure the reasonableness of COE estimates produced by other models. In light of the Commission's statements limiting the manner in which a model such as the risk positioning model could be use in a COE analysis, it was incumbent on PGE to explain why the Commission should use the model results as the basis of a COE estimate. PGE failed to do so.

- If the results of PGE's risk positioning model are used as a check for reasonableness, a comparison between the results of PGE's risk positioning model and every other model result in the case, which includes other models employed by PGE as well as by ICNU/CUB and staff, shows that the risk positioning model results are too high. The range of COE estimates produced by the RPM starts at 11.1 percent. 11.1 percent is at the top of, or exceeds, the range for every other model used in this docket, including those used by PGE.

- PGE's assertion that it "operates in a risk environment that is more risky and uncertain than that of the electric utility industry on average[,]" is inconsistent with the results of its own analysis. If PGE is correct, its COE analysis based on a selection of companies that are comparable to PGE should have resulted in COE ranges higher than that produced by PGE's risk positioning model, which is not limited to PGE-comparable companies, but merely analyzes returns authorized for utilities around the nation in recently litigated cases. Instead, PGE's analysis based on the returns authorized for various utilities around the nation results in a COE range that is considerably higher than ranges produced by PGE, as well as staff, ICNU and CUB, based on companies directly comparable to PGE.

- PGE argues that staff's COE estimate is unreasonably low. However, staff's estimate is within PGE's recommended range. This is particularly notable in light of the fact PGE's recommended range is based in part on the unrealistically high estimates produced by its risk positioning model.

[72] Order No. 01-777 at App A.

- In direct testimony, PGE's COE estimate was based on a proposed capital structure of approximately 56% equity and 44% debt. PGE asserted that an adjustment to its COE would be necessary if its COE is based on a debt structure with less equity. This argument appears to be disingenuous, because PGE proposes a capital structure with only 53% equity in its sur-surrebuttal testimony, but does not propose a concomitant adjustment to its COE estimate.

1. Legal standard.

In 1944, the United States Supreme Court established the standard for determining cost of capital allowance in utility ratemaking proceedings:

> [T]he return to equity owner should be commensurate with returns on investments in the other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital[.][73]

This standard is captured in ORS 756.040, which provides, in pertinent part:

> Rates are fair and reasonable for purposes of this subsection if rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:
>
> (a) Commensurate with the return on investments having other enterprises having corresponding risks; and
>
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.

2. Capital structure.

Staff's recommended COE assumes a capital structure of 50 percent common equity and 50 percent debt, which mirrors the common equity ratio of the companies in staff's sample group. In Docket No. UE 115, the Commission noted that it is "well understood" that the cost of equity drops as the percentage of common equity in the capital structure increases.[74] Based on this understanding, the Commission adjusted the

[73] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

[74] OPUC Order No. 01-777 at 36.

PGE's cost of equity downward to account for the difference between PGE's capital structure and that of comparable companies on which PGE's COE was based:

> It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity is the capital structure in the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly. [75]

In this docket, staff recommends that the Commission simply determine PGE's COE using the same capital structure found in the sample of comparable companies staff used to determine PGE's COE, rather than use a capital structure that differs from that of the comparable companies and adjust the COE.

PGE opposes staff's proposed capital structure, arguing that adopting the staff's proposed capital structure would reduce its financial flexibility. PGE acknowledges that it would not be compelled to alter its capital structure to match a Commission-imposed structure, but argues that it would disincented to maintain an equity level that is higher than that adopted by the Commission because it would not be compensated for it. PGE does not understand staff's analysis or the Commission's adjustment in Docket No. UE 115.

PGE has not been publicly traded for a sufficient period to allow a direct analysis of its COE. Accordingly, it is necessary to use a comparable sample of companies to estimate PGE's COE. One consequence of using a comparable sample of companies to estimate PGE's COE is that the COE obtained from the analysis of the comparable companies may be overstated or understated if the average equity ratio of the comparable companies differs from PGE's. Accordingly, when setting PGE's COE, it is necessary to either assume the same capital structure used to obtain PGE's COE estimate or adjust the COE estimate. Either way, the Commission will obtain the same result.

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[75] *See* OPUC Order No. 01-777 at 36.

If the Commission adopts a COE for PGE that is based on an examination of comparable companies that have equity ratios lower than PGE's, PGE will be overcompensated. Nonetheless, this is what PGE asks the Commission to do.

In any event, PGE's argument that staff's proposed capital structure will artificially limit PGE's financial flexibility appears to be factually incorrect. In fact, it appears that staff's equity ratio of 50 percent is consistent with PGE's target capitalization structure. Specifically, on November 7, 2006, PGE reported to the Edison Electric Institute that its target debt ratio is 50% in 2007, 51% in 2008 and 50% in 2009.[76] This means that PGE's target equity ratio for 2007 and 2009 can be no higher than 50% and no higher than 49% for 2008.

3. Cost of equity

A. Both PGE and staff applied DCF models.

Staff applied two different multi-stage DCF models in addition to a single-stage DCF model to a carefully selected sample group of 12 companies, and also conducted sensitivity analysis, to obtain its COE estimate. The Commission relied on DCF models in UE 115, UE 116 and UG 132. The underlying theory of the DCF model is that a firm's current stock price represents the sum of future dividends, discounted to the present. The rate of return of common equity under the DCF model is the rate that compensates investors for risk and time, assuming that the security is efficiently priced. To calculate an investor's expected return on equity, the DCF formula uses the current stock price, the expected dividends in the coming year, and the expected growth rate of future dividends.[77]

PGE also relies on DCF analysis, as well as a risk positioning model, to obtain its COE estimate. PGE applied one multi-stage model to three different sample companies. PGE applied the model to these sample groups three times, varying the terminal growth

[76] Staff/1925, EEI Report at 30. *See also* Staff/1400, Morgan/6.
[77] OPUC Order No. 99-697 at 7 (UG 132).

rate for each application. Specifically, PGE relied on a growth rates estimated using sustainable growth, anticipated Gross Domestic Product ("GDP"), and historic GDP growth rates. If the unreasonably high results of PGE's risk positioning model and DCF analysis based on historic GDP growth rates are discarded, PGE's remaining DCF analysis supports a COE estimate comparable to what staff recommends.

Cost of Equity Summary Results

Model	**Range of Results**
Staff	
Single Stage DCF	8.56 percent to 9.4 percent
2-stage 150-year DCF	8.5 percent to 9.4 percent
3-stage 40-year DCF	8.8 percent to 9.8 percent
PGE	
Multi-stage (Trend (GDP Forecast))	8.36 percent to 8.99 percent
Multi-stage DCF – *br+vs*	8.21 percent to 9.83 percent
Multi-stage DCF – (historic) GDP	10.2 percent to 10.8 percent
Risk Positioning Method – 7-Year Treasuries	11.1 percent to 11.3 percent
Risk Positioning Method – Corporate Bonds	10.50 percent

B. Differences in results from the DCF models used by staff and PGE are attributable to different assumptions regarding long-term growth rates.

The dramatic difference between the COE estimates obtained by PGE's "historic GDP" multi-stage model and the estimates obtained by the DCF models applied by staff as well as PGE's "*br+vs*" model is due to high terminal growth rate PGE assumed in the historic "GDP" model. Staff assumed long-term growth rates of 4.0 to 5.0 percent and used three different methods to obtain these assumptions: (1) analysis of market consensus growth rates (financial analysts' forecasts); (2) sustainable growth; and (3) historical utility growth rates.

The Company also used three methods to estimate long-term growth: (1) a "sustainable growth" rate method similar to what staff used, which obtained an average estimate of 4.78; (2) a forecast of GDP growth, which obtained an estimate of 5.01 percent; and (3) a 40-year average calculation of historical GDP growth, which obtained a long-term growth rate estimate of 6.76 percent. The Company's 4.78 and 5.01 percent assumptions are similar to the assumptions used by staff. PGE's long-term growth rate assumption based on a 40-year calculation of historical GDP is unrealistically high, and should be rejected.

More specifically, the growth rate produced by the 40-year calculation of historical GDP is more than two hundred basis points higher than the estimates obtained by PGE using different methods, is greater than PGE or the electric industry has experienced on average, is based only on nominal GDP, and disregards analyst estimates, sustainable growth rate calculations, and historic growth rates. Furthermore, this growth rate is clearly higher than PGE's own long-term growth target.[78]

Specifically, in its November 7, 2006 report to the Edison Electric Institute, PGE reported that its "[e]arnings [are] expected to grow 4 to 5 percent over the long term."[79] In light of PGE's expectation that its earnings will grow 4 to 5 percent over the long-term, its COE estimate based in large part on an assumption that its earnings will grow at a rate close to 7 percent should simply be rejected. Once these results are rejected as well as the results from PGE's risk positioning model, which is discussed below, the DCF results discussed in PGE's opening testimony appear to be within a reasonable range and are consistent with the results of staff's analysis.[80]

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[78] Staff/1000, Morgan/17.
[79] Staff/1925, EEI Report/ 29.
[80] Staff/1000, Morgan/23.

C. PGE's criticisms of staff's COE analysis are without merit.

PGE attacks staff's COE analysis on two fronts. A witness PGE introduced in its rebuttal testimony, Thomas Zepp, offers technical criticism to accompany the variety of criticisms made by PGE witnesses Hager and Valach. Staff will briefly address the complaints raised by PGE witnesses Hager and Valach before turning to Dr. Zepp's testimony. Before doing so, staff notes that notwithstanding PGE's many complaints with staff's analysis, the fact remains that the results PGE obtained with its own DCF analysis, other than that based on historic GDP growth, are consistent with the results obtained by staff.

i. Hager-Valach arguments.

Argument 1: Staff only uses one method, the DCF model, to evaluate PGE's required ROE. The significance of this argument is not readily apparent. Certainly the Commission should not reject staff's analysis because it is based on only multi-stage DCF models. Further, the Commission may determine the reasonableness of the results of staff's analysis by comparing it to COE estimates obtained by PGE and ICNU and CUB. As already noted, staff's results are consistent with PGE's analysis that does not rely on the risk positioning model or unreasonably high estimates of long-term growth.

Argument 2: Staff made no reference to the standards of setting just and reasonable rates required by *Hope, Bluefield,* and ORS 756.040. Staff is not obligated to put legal analysis into its testimony, and thus, cannot be faulted for not setting forth the legal standards. An examination of staff's testimony reflects that its COE estimate is in fact predicated on the appropriate legal standards. For example, staff includes an exhibit that analyzes the return expected by electric utilities (Staff/1003, Morgan/37-40). Staff also testifies that its COE estimate is not "extreme" when compared to recently set COEs around the country (Staff/1400, Morgan/13-15); there is no indication that a 9.40 COE would cause PGE to experience a ratings downgrade (Staff/1400, Morgan/18-21); staff considered the final results of its model in light of the expected return to the overall market (Staff/1400, Morgan/23); the results of other commissions indicate that staff's COE estimate is not out of line with other commissions (Staff/1400, Morgan/29); and staff checked the reasonableness of its COE recommendation against overall market expectations (Staff/1400, Morgan/47).

Argument 3: Staff did not follow their own criteria in the selection process for their sample group of companies. In its rebuttal testimony, PGE specifically criticized staff's inclusion of two specific companies in staff's sample of proxy companies. In surrebuttal testimony, staff agreed that these companies should be excluded from its analysis, noting that one of them had been improperly included and that the other's credit had deteriorated since staff's initial analysis. Staff updated its analysis using the new sample of companies.[81]

PGE also made more general criticisms regarding staff's selection of proxy companies. These criticisms are not persuasive. Staff's selection process was more detailed than PGE's process. PGE merely used two samples that were included in broad industry classifications and simply eliminated companies that had changed dividend payments. PGE's third sample was comprised of Staff's sample from Docket UE 170.

Argument 4: After performing their DCF analysis on their sample group of companies, staff failed to make any adjustments to reflect PGE-specific risks.

Adjusting a COE obtained by analyzing proxy companies for company-specific risks would be a departure from the way in which the Commission has previously determined COE. To the extent PGE thinks such adjustments should be made, PGE is obligated by the Commission's Guidelines for Cost of Equity Witnesses to explain why.[82]

Further, PGE did not establish PGE is any more risky than comparable companies, or attempt to quantify the alleged risk faced uniquely by PGE. In absence of

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[81] Staff/1400, Morgan/2.
[82] Order No. 01-777 at App A ("When advocating a new approach * * *, a witness should explain why the Commission should adopt the proposed methodology in the present docket.")

these demonstrations, its argument concerning staff's failure to adjust PGE COE for PGE-specific risk is unpersuasive.

Argument 5: Staff considers only Oregon regulatory decisions and policy and does not attempt to evaluate its analysis alongside those used in other regulatory environments. The Commission has made clear that examination of ROE decisions in other states is pertinent only to provide confirmation of a decision, and is not an independent basis on which to base a COE determination.[83] Staff testified that it considered the results from other commission decisions that demonstrated staff's proposals are not out of line with other Commission decisions.

In fact, staff's analysis refutes another PGE criticism that staff's COE estimate is "extreme" when compared to results in other states. As staff testified, PGE makes this assertion without attempting to control for the various factors that influence the COE. For example, focusing on only the COE without considering capital structure leads to erroneous conclusions.

Staff presented a table that sets forth 16 regulatory decisions in 2004 and 2005. The table shows that while the COE in these decisions averaged 10.3 percent, the percentage of equity in the capital structure averaged only 41.13 percent. It also shows that, considering both figures together, these commissions have adopted average "contributory returns to equity," *i.e.*, weighted by the amount of equity in the capital structures, of only 4.23 percent. When COEs authorized by these commissions are adjusted for leverage, adopting staff's 50 percent common equity recommendation and using the range of adjustment for decreased leverage identified in UE 115, the average range is from 9.15 percent to 9.95 percent.[84]

Argument 6: Staff's DCF analysis inappropriately relies upon a one-day spot price to calculate the dividend yield component. Staff's reliance on the one-day spot

[83] Order No. 01-777 at 34.
[84] Staff/1400, Morgan/13.

price to calculate the dividend yield component of the DCF model is consistent with Commission precedent. In UG 152, the Commission rejected NW Natural's request to the Commission to use an average stock price, rather than the most recent stock price, to determine dividend yield component, quoting a previous Commission order in which the Commission stated:

> Conceptually, the stock price to use is the current price of the security at the time of estimating the cost of equity. In an efficient market, the current stock price provides the best information of future prices. An efficient market implies that prices adjust instantaneously to the arrival of new information. Therefore, current prices reflect the fundamental economic value of the security.[85]

PGE's argument is puzzling in light of the Commission's previous decisions on the use of the one-day spot price. In fact, it is incumbent on PGE to explain its departure from this practice under the Commission's Cost of Equity Witness Guidelines.

In any event, PGE's argument is misplaced in light of the fact that staff based its COE estimate on a cohort sample of companies. One advantage of using a cohort sample is that even if anomalous pricing behavior may be found for a portion of the sample on any given day, the effect should not skew the results. This is because the larger sample of companies will reduce the impact of any anomalous pricing.[86]

Argument 7: Staff ailed to consider capital structure requirements imposed by existing Commission orders. Staff responded to this argument above.

Argument 8: Although staff claimed to reject use of historical GDP growth rates in DCF model, they consider historical growth rates in their analysis. There is a fundamental difference between considering historic information when determining a COE, and concluding that the appropriate long-term growth rate to use for a DCF analysis is based on historic GDP growth. Little more needs to be said in response to this argument.

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[85] *See* Order No. 99-697 at 14, *quoting* Order No. 94-336.
[86] Staff/1400, Morgan/32.

Argument 10: Staff incorrectly evaluates the impact of institutional ownership in their DCF analysis. Staff asserted that ownership of shares by large institutions "can create stability in share pricing." Advice obtained by PGE from Lehman Brothers supports staff's assertion.[87]

ii. Dr. Zepp's criticisms of staff's COE analysis are also without merit.

Dr. Zepp's criticism of staff's DCF analysis is predicated in part on results he obtained using staff's DCF model, but modifying the assumptions. More specifically, Dr. Zepp attempts to discredit staff's DCF analysis by replicating it, using different assumptions. That Dr. Zepp obtained different results using different assumptions is certainly not noteworthy. It is also not probative of an appropriate COE because his assumptions are unrealistic or inappropriate.

The primary changes that Dr. Zepp makes to staff's DCF model are to include a higher terminal ROE, to include a "v x s" factor adjustment, and to apply initial growth rates based on a calculation of historic growth he believes should be applied on a going-forward basis. Dr. Zepp's first two changes are inappropriate because the terminal growth rate assumed by staff implicitly includes the impact of the "v x s" factor.[88] Because Dr. Zepp "double-counts" the impact of selling shares, he generates a higher growth rate factor in the model.

The primary impact of Dr. Zepp's adjustments is that the first-stage growth is 7.6 percent in one version and 8.8 percent in the other version, with the first stage in the first version extending five years and the first stage in the second version extending ten years.

To expound on this concept, Dr. Zepp calculates the 7.6 percent figure based on the earnings growth from 1996-2005. He then applies it to the ten-year future period. Similarly, he calculates the 8.8 percent growth as the rate from 2001-05, and applies this

[87] *See* Staff/1400, Morgan/29 (Confidential).
[88] Staff/1400, Morgan/38.

to the future five-year period.[89] Ultimately, the terminal ROE in both versions is 12.97 percent.[90]

Dr. Zepp's 12.97 percent terminal ROE is beyond the range of reasonableness for the sample companies. As already noted, staff proposed a growth rate of between 4 and 5 percent. A growth rate in the 4 to 5 percent range is the growth rate that PGE obtained with two of the three methods it used to obtain a growth rate and also, is PGE's expected long-term growth rate. Dr. Zepp's extreme results simply must be disregarded.

iii. PGE failed to prove that staff's COE estimate and capital structure recommendation would push PGE closer to investment grade. All PGE's cost of capital witnesses criticize staff's COE estimate on the ground that the estimate and staff's proposed capital structure would push PGE "closer to non-investment grade." The argument is not supported by persuasive evidence. Essentially, the evidence in support of PGE's argument boils down to PGE's assertion that staff's recommended capital structure and COE recommendation could "conceivably" affect PGE's bond rating.[91] This assertion is too speculative to be persuasive. Second, it is not supported by a solid factual foundation.

PGE's criticisms rely on analysis regarding PGE's "financial ratios" in 2007 assuming staff's recommendations are adopted. Its reliance on this analysis is misplaced because credit ratings are based on more than a utility's financial ratios and are based on a period of time longer than one year.[92]

Furthermore, PGE's argument that staff's capital structure proposal pushes PGE closer to non-investment grade is not credible in light of the fact that PGE's own reports reflect that it expects an equity ratio of 50 percent or less in 2007-09.

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[89] Staff/1400, Morgan/39.
[90] Staff/1400, Morgan/40.
[91] PGE/2000, Hager-Valach/28.
[92] Staff/1400, Morgan/16-21.

D. The additional models that Dr. Zepp presented in PGE rebuttal testimony are not persuasive.

In addition to critiquing staff's analysis, Dr. Zepp testifies regarding results of three additional financial models that he believes support PGE's COE estimate. The new models do little to inform the Commission regarding the appropriate COE for PGE. First, no evidence demonstrates that the water utilities analyzed in the first new model, a single-stage DCF model, are comparable to PGE. Furthermore, the terminal growth rate in the model is higher than the growth in the overall economy. A basic tenet of economics is that companies cannot grow faster than the economy in the long run. Accordingly, the results of the first model are questionable at best.

The second new model is a risk premium analysis using the years 1986 to 2006, and is based on the assumption that Value Lines reported short-term growth is a reasonable proxy for perpetual growth in the overall market. The model reflects the industrial companies that Value Line analyzes are expected to grow at an average rate of 12.68 percent, which is an untenable level of growth in light of the tenet identified above.

The third new model is also a risk-premium analysis based on a sample of what are described as "Moody's Electric Utility" companies. This model has several weaknesses, including (1) use of a very broad base of companies, including those that are not purely rate regulated; (2) use of general corporate bond rates, not the actual rates of the sample companies; (3) a failure to address an overall decrease in risk premiums; and (4) a failure to identify the appropriate holding period assumptions.[93]

E. The Commission should reject PGE's risk positioning model.

In addition to a two-stage DCF model, PGE employs a univariate regression analysis that PGE refers to as a "risk positioning model" ("RPM") to obtain a COE estimate. Staff recommends that the Commission reject PGE's analysis based on its

[93] Staff/1400, Morgan/37.

RPM for several reasons. First, the Commission has previously rejected this model and PGE provides no explanation as to why the Commission should nonetheless accept it in this docket. Second, PGE's modeling has several infirmities, including the omission of relevant variables. Third, PGE provides no theoretical support for the model.

i. PGE's RPM violates this Commission's published guidelines.

PGE's use of the RPM in UE 180 violates the Commission's Cost of Equity Witness Guidelines adopted in the last general rate case filed by PGE. Those guidelines specify,

> All witnesses should clearly and fully explain the methodologies used and the theoretical support for using the methodologies. When advocating a new approach, or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology in the present docket.[94]

PGE actually presented the RPM in the case in which the Commission adopted its Cost of Equity Witness Guidelines. The Commission rejected the methodology. In doing so, the Commission noted it had rejected a similar methodology in a 1999 rate case involving another utility:

> This Commission rejected a similar risk-positioning method proposed by another utility in a recent rate case.[] We reach the same conclusion here. As Staff notes, PGE's proposed methodology using authorized ROEs and yields on treasuries and corporate bonds is unconventional and has not been accepted by regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding.[95]

It appears that at least in part, the Commission adopted its Cost of Equity Witness Guidelines in response to PGE's presentation of the RPM in the 2001 rate case. Nonetheless, PGE still fails to explain why the Commission should rely on the RPM in this docket even though the Commission has now twice rejected it.

PGE presented the RPM in its direct testimony with only one change from the model presented in Docket No. UE 115, it updated a few years of authorized ROEs and

[94] Order No. 01-777 at App A.
[95] Order No. 01-777 at 33 (footnote citing order No. 99-697 omitted).

interest rates. In fact, PGE stated that it didn't go back and try to update its original analysis done in 1998.[96] In absence of any explanation as to why it is appropriate to rely on the RPM in this docket, notwithstanding the Commission's previous rejection of the model, the Commission should reject it again.

ii. PGE's RPM is flawed from a regulatory perspective

Using the RPM to determine a utility's COE is fundamentally flawed for several reasons. First, the RPM uses hopelessly circular logic. In other words, use of the RPM to set a COE would simply make such a determinations a never-ending loop among Commissions, *i.e.*, Washington would use Oregon utilities' COE to determine COE for Washington utilities, Oregon would then use Washington utilities' COE to set use the COE for utilities in Oregon, etc.[97] This loop would replace independent analysis based on current market conditions, which as staff points out in its testimony, is wholly inappropriate.

> "[t]he cost of equity, as I discussed at length, is based on the required returns of investors and simply averaging other ROE decisions from other jurisdictions is circular and cedes the important authority for ROE decisions in Oregon to the ROE decisions in other states. In other words, the market sets the required ROE, not other Commissions."[98]

Second, the RPM relies on decisions of other jurisdictions over an unreasonably long period of time. There is no reason to assume that a COE determined by a regulatory commission in one year is probative of the COE that should be determined by another regulatory commission the next year. Similarly, the RPM ignores the fact that an analysis relying only on the final COE determined by a particular Commission is not particularly meaningful if the circumstances underlying that COE decision are not also considered. This Commission made a similar point in its order in PGE's last general rate case:

> Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket. Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the

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[96] Staff/1102, Conway/19 (PGE's Response to Staff Data Request 91).
[97] Staff/1000, Morgan/24.
[98] Staff/ , Morgan/ .

> reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions to base an ROE award for a utility.[99]

The Commission further addressed this issue in PacifiCorp's 2001 general rate case, stating,

> Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those market conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in the traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.[100]

iii. RPM lacks a theoretical foundation.

Finally, PGE's RPM lacks a theoretical foundation. Rather than supporting the model with scholarly journal articles or other such proof of a theoretical foundation, PGE merely states that,

> "[it] established a hypothesis regarding interest rates and authorized ROEs; we then tested our hypothesis, and verified our results. Once we had determined that interest rates were the most important variable, we limited our analysis to one variable." See PGE/2700, Hager-Valach/25.

As the Commission concluded in 2001, PGE's RPM "is unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity."[101] PGE's assertion that it tested the hypothesis underlying the RPM is not sufficient to demonstrate this Commission should adopt this unconventional method in this docket. This is particularly true in light of the fact that the extent to which PGE actually tested its hypothesis is not clear.

iv. PGE's RPM is flawed from a financial analysis perspective.

PGE's RPM is flawed from a financial analysis perspective because it omits relevant factors such as capital structure. Further, as demonstrated by PGE itself, the R-

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[99] Order No. 01-777.
[100] Order No. 01-787.
[101] Order No. 01-777 at 33.

squared is not correct when using its RPM.[102] However, this is the criteria PGE used to determine that the data fit the model quite well. Staff further points out that even if the R-Squared is not flawed, it is inappropriate for PGE to conclude its model was quite good for a pooled cross sectional regression.[103]

v. The RPM is flawed from a statistical perspective

PGE's RPM lacks relevant variables and the reported statistics of the RPM are fallacious. In PGE's rebuttal testimony, PGE produced an "alternate form of the RPM." PGE also produced an analysis that demonstrates that the predicted results are the same as PGE's original form of the RPM. PGE demonstrates that the R-Squared and t-statistics are not incorrectly specified (as they are in the original specification) but, PGE discards the alternate form of the model and continues reporting results and statistics for the original form. The production of the alternate form regression is a red herring. If PGE has a model that has identical predicted values and does not suffer from fallacious statistical results, then why does PGE not advocate for that model? Discarding the RPM in favor of the "alternate model" would have simplified the discussion regarding PGE's regression analysis. However, both the RPM and the alternate form of the model likely suffer from omitted variable bias which can cause statistical tests to be misstated. PGE admits that its model lacks relevant factors considered by commissions in authorizing ROEs.[104] PGE further admits that bias is a concern. Yet, PGE continues to advocate for its simplistic single-variable model. In a nutshell, PGE's argument seems to be that if you are unable to produce a perfect model, why try?

vi. RPM application is flawed from a practitioners' perspective

[102] PGE/2700, Hager-Valach/28 lines 8-12.
[103] See Staff/1300, Conway/21 line 19 to Conway/22, line 18.

[104] PGE/2000, Hager-Valach/57, lines 18-19.)

PGE's RPM is flawed from a practitioners' perspective because PGE failed to conduct basic statistical tests. In response to this criticism, PGE responds that it did not have a "full cross-sectional time series data set." With respect to the cross-sectional data, PGE states that they have "some cross-sectional data, but not for all the jurisdictions in any month." With respect to the time-series data, PGE states that they have "some time series data, but not consistently for any jurisdiction." With respect to whether they should have performed cross-sectional statistical tests, PGE responds, "[n]o. There is no logical grouping to the data." With respect to whether they should have performed time-series statistical tests, PGE responds "[n]o. There is no logical grouping to the data."[105]

Puzzlingly, in PGE's final round of testimony, PGE now claims the data has "a very obvious logical grouping" and that it performed the standard statistical tests such as R-squared, Adjusted R-squared, F-statistic, and t-statistic. However, this argument puts the Commission back to square one. Staff demonstrated that the F-test and the t-test provide identical results for a univariate regression.[106] Further Staff demonstrated that PGE's reported t-statistic, R-squared, and Adjusted R-squared are fallacious.[107]

PGE's reliance on the original flawed statistics in its sursurrebutal testimony is misleading. Staff's criticism was very specific -- PGE did not run any basic statistical tests to check for common problems. Staff testified regarding the benefit of such tests:

> In its simplest terms, the tests would determine if the relationship between authorized ROEs and Treasury rates are stable over time and across jurisdictions (are the parameters stable). Additionally, the tests would determine if the variations of the estimates vary across either time or jurisdiction (e.g., does the model suffer from either heteroskedasticity or autocorrelation?). These basic statistical tests are generally performed to see if it is reasonable to assume that the model reflects the assumptions embedded in standard regression analysis.[108]

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105 PGE/2000, Hager-Valach/61, lines 11-20..

106 Staff/1100, Conway/11, lines 6-7.
107 Staff/1100, Conway/6 line 10 through Conway/8, line 12.
108 Staff/1300, Conway/9, lines 2-9.

The problem PGE's rebuttal to Staff's criticism is that PGE seems undecided whether the model is intended to predict or explain. PGE rebuts this criticism by explaining, "If underlying assumptions do not change significantly, a model that has a good fit will also predict well. They key is the underlying assumptions."[109] The problem with PGE's assertion is that it has no evidence that the underlying assumptions did not change. That evidence would have come from the basic statistical tests advocated by Staff that PGE declined to run.

PGE's rebuttal of Staff titled "Model Statistics are solid" is a complete red herring. PGE completely mischaracterizes and inaccurately describes the analysis Staff conducted using Shazam. Staff adopted Shazam because Excel did not produce the AIC and BIC statistics PGE was now relying upon. The results of Staff's Shazam demonstration are clear. The AIC and BIC statistics are identical between alternate forms of the models due to the way they are set up.

PGE follows this analysis with its meatloaf example.[110] Staff never advocated for a regression model to forecast this commission's cost of equity decision. Staff is advocating against such a model. However, the correct use of PGE's example of meatloaf is that PGE has provided the Commission with a pound of raw ground beef and is claiming it is a delicious meatloaf. Staff's criticism of PGE's meatloaf is that it is missing the other crucial ingredients such as bread crumbs and that PGE did not do any basic testing of its meatloaf (e.g., test to determine if it was heated sufficiently to kill bacteria).

IV. Conclusion.

For the reasons stated above, the Commission should adopt staff's recommendations regarding PGE's NVPC, its proposed power cost adjustment

[109] PGE/2700, Hager-Valach/26 lines 7-9.
[110] See PGE/2700, Hager-Valach/27.

mechanisms, staff's proposed power cost adjustment mechanism and staff's cost of capital recommendations.

DATED this 20th day of November 2006.

Respectfully submitted,

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Qty	Issue	Customer Price	YTM	Coupon	Maturity	Min. Qty	Payment Months	Notes
10001	T-NOTE	98.402	4.941	2.75	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	98.769	4.935	3.25	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	100.847	4.948	6.125	8/15/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	99.261	4.958	4	8/31/2007	10	Feb,Aug	Non Callable
10001	T-NOTE	97.812	4.821	3	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	100.82	4.809	5.5	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	98.265	4.818	3.375	2/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	99.749	4.823	4.625	2/29/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	99.034	4.703	4.125	8/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	97.581	4.703	3.25	8/15/2008	10	Feb,Aug	Non Callable
10001	T-NOTE (DBL OLD 2YR)	100.234	4.733	4.875	8/31/2008	10	Feb,Aug	Non Callable
10001	T-NOTE	96.523	4.643	3	2/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	99.679	4.649	4.5	2/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	97.187	4.599	3.5	8/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	103.534	4.614	6	8/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE (OLD 3YR)	100.667	4.611	4.875	8/15/2009	10	Feb,Aug	Non Callable
10001	T-NOTE	105.745	4.574	6.5	2/15/2010	10	Feb,Aug	Non Callable

10001	T-NOTE	96.8	4.569	3.5	2/15/2010	10 Feb,Aug	Non Callable
10001	T-NOTE	104.128	4.538	5.75	8/15/2010	10 Feb,Aug	Non Callable
10001	T-NOTE	98.558	4.546	4.125	8/15/2010	10 Feb,Aug	Non Callable
10001	T-NOTE	101.921	4.497	5	2/15/2011	10 Feb,Aug	Non Callable
10001	T-NOTE	99.859	4.535	4.5	2/28/2011	10 Feb,Aug	Non Callable
10001	T-NOTE	102.202	4.479	5	8/15/2011	10 Feb,Aug	Non Callable
10001	T-NOTE (DBL OLD 5YR)	100.366	4.538	4.625	8/31/2011	10 Feb,Aug	Non Callable
10001	T-NOTE	101.723	4.501	4.875	2/15/2012	10 Feb,Aug	Non Callable
10001	T-NOTE	99.332	4.507	4.375	8/15/2012	10 Feb,Aug	Non Callable
10001	T-NOTE	96.493	4.524	3.875	2/15/2013	10 Feb,Aug	Non Callable
5001	T-BOND	112.262	9.491	12	08-15-2013C	10 Feb,Aug	Callable
10001	T-NOTE	98.332	4.539	4.25	8/15/2013	10 Feb,Aug	Non Callable
10001	T-NOTE	96.637	4.549	4	2/15/2014	10 Feb,Aug	Non Callable
5001	T-BOND	120.153	8.846	12.5	08-15-2014C	10 Feb,Aug	Callable
5001	T-NOTE	98.082	4.545	4.25	8/15/2014	10 Feb,Aug	Non Callable
5001	T-BOND	145.575	4.558	11.25	2/15/2015	10 Feb,Aug	Non Callable
5001	T-NOTE	96.258	4.548	4	2/15/2015	10 Feb,Aug	Non Callable
5001	T-BOND	143.364	4.558	10.625	8/15/2015	10 Feb,Aug	Non Callable
5001	T-NOTE	97.864	4.548	4.25	8/15/2015	10 Feb,Aug	Non Callable

5001 T-BOND	135.012	4.565	9.25	2/15/2016	10 Feb,Aug	Non Callable
5001 T-NOTE	99.582	4.555	4.5	2/15/2016	10 Feb,Aug	Non Callable
5001 T-NOTE (OLD 10YR)	102.414	4.565	4.875	8/15/2016	10 Feb,Aug	Non Callable
5001 T-BOND	135.744	4.618	8.875	8/15/2017	10 Feb,Aug	Non Callable
5001 T-BOND	138.802	4.677	8.875	2/15/2019	10 Feb,Aug	Non Callable
5001 T-BOND	132.705	4.687	8.125	8/15/2019	10 Feb,Aug	Non Callable
5001 T-BOND	137.13	4.702	8.5	2/15/2020	10 Feb,Aug	Non Callable
5001 T-BOND	140.455	4.717	8.75	8/15/2020	10 Feb,Aug	Non Callable
5001 T-BOND	132.337	4.729	7.875	2/15/2021	10 Feb,Aug	Non Callable
5001 T-BOND	135.685	4.735	8.125	8/15/2021	10 Feb,Aug	Non Callable
5001 T-BOND	127.633	4.739	7.25	8/15/2022	10 Feb,Aug	Non Callable
5001 T-BOND	126.726	4.746	7.125	2/15/2023	10 Feb,Aug	Non Callable
5001 T-BOND	117.218	4.747	6.25	8/15/2023	10 Feb,Aug	Non Callable
5001 T-BOND	134.8	4.751	7.625	2/15/2025	10 Feb,Aug	Non Callable
5001 T-BOND	126.179	4.75	6.875	8/15/2025	10 Feb,Aug	Non Callable
5001 T-BOND	115.66	4.749	6	2/15/2026	10 Feb,Aug	Non Callable
5001 T-BOND	125.418	4.751	6.75	8/15/2026	10 Feb,Aug	Non Callable
5001 T-BOND	124.293	4.744	6.625	2/15/2027	10 Feb,Aug	Non Callable

5001 T-BOND	121.422	4.741	6.375	8/15/2027	10 Feb,Aug	Non Callable
5001 T-BOND	110.343	4.733	5.5	8/15/2028	10 Feb,Aug	Non Callable
5001 T-BOND	107.129	4.728	5.25	2/15/2029	10 Feb,Aug	Non Callable
5001 T-BOND	119.375	4.725	6.125	8/15/2029	10 Feb,Aug	Non Callable
5001 T-BOND (OLD 30YR)	109.57	4.708	5.375	2/15/2031	10 Feb,Aug	Non Callable
5001 T-BOND (30YR)	97.554	4.653	4.5	2/15/2036	10 Feb,Aug	Non Callable

(A)	Ledger (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)	Net Proceeds (L) [I-J-K]	Face Amount Outstanding (O)	Net Outstanding (P) [N*O]	Face Amount Weight (Q) [O/Total]	PGE Weighted Rate (R) [Q*M]	Staff Embedded Cost (S)
1	G11514	FMB	5.6675% Series	28-Oct-02	25-Oct-12	10	5.080%	$100,000,000	$817,683	$0	$99,182,317	$100,000,000	$99,182,317	8.038%	0.596%	5.1858%
2	G11515	FMB	5.279% Series	8-Apr-03	1-Apr-13	10	5.080%	$50,000,000	$408,842	$0	$49,591,158	$50,000,000	$49,591,158	4.019%	0.259%	5.1858%
3	G11516	FMB	5.625% Series	4-Aug-03	1-Aug-13	10	5.450%	$50,000,000	$408,842	$1,946,809	$47,644,349	$50,000,000	$47,644,349	4.019%	0.230%	6.0859%
4	G11517	FMB	6.750% Series	4-Aug-03	1-Aug-23	20	6.575%	$50,000,000	$521,342	$1,946,809	$47,531,849	$50,000,000	$47,531,849	4.019%	0.275%	7.0387%
5	G11518	FMB	6.875% Series	4-Aug-03	1-Aug-33	30	6.700%	$50,000,000	$521,342	$1,946,809	$47,531,849	$50,000,000	$47,531,849	4.019%	0.280%	7.0998%
6	G11501	Series MTN	9.31% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0	$19,823,423	$20,000,000	$19,823,423	1.608%	0.151%	9.3986%
7		FMB	6.31% Series	1-Apr-06	1-Apr-36	30	6.310%	$175,000,000	$1,125,000	$0	$173,875,000	$175,000,000	$173,875,000	14.067%	0.855%	6.3583%
7.5		FMB	6.26% Series	1-Apr-06	1-Apr-31	25	6.260%	$100,000,000	$750,000	$0	$99,250,000	$100,000,000	$99,250,000	8.038%	0.489%	6.3201%
8		FMB	Pro fonna series	15-Jun-07	15-Jun-17	10	5.565%	$300,000,000	$2,903,050	$0	$297,096,950	$300,000,000	$297,096,950	24.115%	1.583%	5.6932%
9	G40027	Notes	7.875% Series	13-Mar-00	15-Mar-10	10	7.875%	$149,250,000	$1,472,800	$1,266,000	$146,511,200	$149,250,000	$146,511,200	11.997%	0.975%	8.1468%
10	G21186	PCB	Brdmn 98A Fixed	28-May-98	1-May-33	35	5.200%	$23,600,000	$85,850	$1,267,030	$22,247,120	$23,600,000	$22,247,120	1.897%	0.105%	5.5742%
11	G21185	PCB	Clstrp 98A Fixed	28-May-98	30-Apr-33	35	5.200%	$97,800,000	$355,835	$1,617,373	$95,826,792	$97,800,000	$95,826,792	7.861%	0.419%	5.3278%
12	G21184	PCB	Colstrip 98B Fixed	28-May-98	30-Apr-33	35	5.450%	$21,000,000	$76,420	$438,143	$20,485,437	$21,000,000	$20,485,437	1.688%	0.095%	5.6106%
13	G21191	PCB	Trojan 85A Fixed	1-Jul-98	1-Apr-10	25	4.800%	$20,200,000	$218,352	$244,162	$19,737,486	$20,200,000	$19,737,486	1.624%	0.082%	4.9608%
14	G21193	PCB	Trojan 85B Fixed	1-Jul-98	1-Jun-10	25	4.800%	$16,700,000	$180,519	$184,473	$16,335,008	$16,700,000	$16,335,008	1.342%	0.068%	4.9534%
15	G21195	PCB	Trojan 90A Fixed	1-Jul-98	1-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	$9,311,249	$9,600,000	$9,311,249	0.772%	0.043%	5.5358%
16	G21196	PCB	Troj Ser 1990B-Fixed	15-Dec-90	15-Dec-14	24	7.125%	$5,100,000	$163,234	$0	$4,936,766	$5,100,000	$4,936,766	0.410%	0.030%	7.4123%
17	G21123	PCB	Coyote 96 Float	1-Dec-96	1-Dec-31	35	3.500%	$5,800,000	$159,350	$0	$5,640,650	$5,800,000	$5,640,650	0.466%	0.017%	3.6395%
			Loss on Reacquired Debt							$0	$0					
			Total Debt					$1,244,050,000	$10,448,808	$11,042,588	$1,222,558,604	$1,244,050,000	$1,222,558,604	100.00%	6.1984%	

CERTIFICATE OF SERVICE

I certify that on November 20, 2006, I served the foregoing Amended Staff Opening Brief upon all parties of record in this proceeding by electronic mail and by mailing a copy by postage prepaid first class mail or by hand delivery/shuttle mail to the parties accepting paper service.

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