Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Maury Galbraith. The Public Utility Commission of Oregon (OPUC) employs me as a Senior Economist. My qualifications are shown on Exhibit Staff/101.

<u>Introduction and Summary</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I describe Portland General Electric's (PGE) proposed Hydro Generation Adjustment (HGA) mechanism, the company's arguments for why an HGA mechanism is needed, and the company's justification for the design of the HGA mechanism. Second, I present staff's analysis of the HGA mechanism and the arguments supporting its approval. Third, I present the staff's proposed long-term Power Cost Adjustment (PCA) mechanism and indicate why staff believes it is preferable to PGE's HGA mechanism. Fourth, I present staff's recommendations for enhancing the modeling of net variable power costs (NVPC). Finally, I present an interim PCA mechanism that can be applied prior to implementation of staff's proposed long-term PCA.

Q. DOES STAFF PRESENT ANY OTHER WITNESSES IN THIS FILING?

A. Yes. Bryan Conway, Program Manager of Economic Research and Financial Analysis, addresses the issues raised in the Return on Equity testimony of Jeff D. Makholm, Ph.D., and the Cost of Capital testimony of Patrick Hager in this docket. Staff Exhibit 200.

Q. PLEASE SUMMARIZE STAFF'S OVERALL TESTIMONY.

A. Staff makes the following recommendations:

- The Commission should consider reasonable risk reduction, neutral cost recovery, and equal treatment criteria when evaluating automatic adjustment clauses. These criteria are additions to PGE's rate stability, regulatory transparency, and incentive for good management criteria.
- The Commission should reject PGE's proposed HGA mechanism. The $2.5 million deadband removes nearly all of PGE's hydro-related earnings risk and fails the reasonable risk reduction criterion. Tracking asymmetric financial impacts with the symmetrically designed HGA mechanism would result in an expected economic windfall for PGE and therefore fails the neutral cost recovery criterion.
- The Commission should indicate a preference for Expected Value Power Cost modeling. Modeling the uncertainty associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability provides a more realistic simulation of PGE's system operations and produces a distribution of NVPC that can be used to design a fair PCA mechanism.
- The Commission should indicate a preference for a PCA mechanism with a deadband set: (1) to exclude a reasonable range of normal variation from triggering the PCA mechanism, and (2) to be neutral on an expected recovery basis. For example, a deadband set at the 10^{th} and 90^{th} percentiles of the 'All-in' NVPC distribution, as distinguished from the 'Hydro-only' NVPC distribution, would satisfy these criteria.
- The Commission should indicate a preference for updating the PCA deadband annually to account for changing economic relationships. When underlying economic conditions change (for example a change in the

hydroelectric generation and electricity market price relationship) prior NVPC modeling and any associated findings or conclusions become invalid.

- The Commission should adopt an interim PCA for calendar years 2005 and 2006. The deadband should be set at an amount equal to the revenue requirement effect of plus and minus 250 basis points of ROE.
- The Commission should ensure any proposal does not incent direct-access eligible customers on their choice to go direct access or remain with the company.

PGE's Hydro Generation Adjustment Mechanism

Q. PLEASE SUMMARIZE PGE'S PROPOSED HGA MECHANISM?

A. PGE has constructed the HGA mechanism as an automatic adjustment clause under ORS 757.210. The HGA has the following attributes:

1. The HGA tracks the monthly on-peak and off-peak difference between actual hydro generation and the annual Resource Valuation Mechanism (RVM) forecast of hydro generation.
2. The HGA values any difference between actual and forecast hydro generation using monthly on-peak and off-peak Mid-Columbia index prices.
3. The HGA applies a symmetric deadband of $2.5 million to the annual value of any difference between actual and forecast hydro generation. Amounts exceeding plus-or-minus $2.5 million would be placed in a balancing account for later offset or amortization.
4. The HGA triggers amortization of the balancing account whenever the cumulative balance exceeds plus-or-minus $20 million. The HGA rate is calculated using a three-year amortization period and is reset annually.

Whenever the account balance recedes below $20 million the amortization rate would be reset to zero.

5. The HGA rate will be applied to all customers except those customers who have chosen direct access for the five-year minimum term.

Q. WHAT IS THE PROBLEM THAT PGE INTENDS TO REMEDY WITH COMMISSION APPROVAL OF THE HGA MECHANISM?

A. PGE offers the HGA mechanism as the best response to the problem of increased earnings risk associated with hydroelectric generation. PGE witness Lesh opens her policy testimony with a clear statement of the problem:

> PGE's resource stack contains a significant amount of hydroelectric generation, the production from which depends primarily upon weather. Because of the paradigm shift in wholesale markets during the 1990s, the effects of which became clear after 2000, the cost-of-service variability associated with weather-driven changes in hydro production has increased by magnitudes. PGE Exhibit 100 Lesh/1.

Q. ACCORDING TO PGE, WHAT IS THE KEY TO UNDERSTANDING THE ORIGIN OF THIS PROBLEM?

A. The key is that the magnitude of the financial impact of hydro variability has recently increased. PGE witness Lobdell discusses the recent changes in the economics of hydro variability and quantifies the recent change:

> [A] 50 MWa deviation in annual hydro production now has an impact of almost $22 million, whereas it would have had an impact of only approximately $9 million in the mid- 1990s… PGE Exhibit 200 Lobdell/21.

Q. DOES PGE ADDRESS THE INCREASED FINANCIAL IMPACT OF HYDRO VARIABILITY FROM THE EARNINGS PERSPECTIVE?

A. Yes. PGE witnesses Tinker and Niman in a White Paper titled, "Financial Impact of Hydro Variability," suggest that the impact of hydro variability could be large compared to PGE's earnings:

> Under the assumption of a moderate relationship between hydro production and market electric prices, annual financial impacts vary from a loss equal to approximately 30 percent of authorized pre-tax earnings to a gain equal to approximately 21 percent of these authorized annual earnings. PGE Exhibit 301 Niman – Tinker/9.

Q. DOES PGE ADDRESS WHETHER THE COMPANY'S CURRENT AUTHORIZED RETURN ON EQUITY (ROE) COMPENSATES PGE'S INVESTORS FOR THIS INCREASED HYDRO-RELATED RISK?

A. Yes. PGE witness Hager cites two reasons why PGE's required ROE is now higher than the ROE authorized in Docket UE 115 (i.e., PGE's last general rate case):

> First, in 2000, investors would still have perceived hydro risk as relatively small, based on experience during the 1990s. As Mr. Lobdell explains, a 50 MWa swing in the mid 1990s would affect earnings by only about $9 million, not the $20 million or higher we could experience today. Second, for UE 115, PGE had a comprehensive PCA, as did all but two of the utilities used as comparable companies. We no longer have a PCA. This means both that the risk is higher and the volatility greater. These effects increase the required return on equity. PGE Exhibit 600 Hager/ 19.

Q. DOES PGE IDENTIFY POTENTIAL RATEMAKING RESPONSES TO THIS INCREASED HYDRO-RELATED EARNINGS RISK?

A. Yes. PGE witness Lesh suggests that the Commission must choose one of two possible responses. Either raise PGE's cost of equity and debt capital, or supplement test year ratemaking with an automatic adjustment clause. PGE Exhibit 100 Lesh/2.

Q. DOES PGE REQUEST A HIGHER AUTHORIZED ROE IN THIS DOCKET?

A. No. PGE recommends the HGA mechanism as a method of bringing PGE's current earnings risk back in line with its historical risk profile and the risk profile of the sample group of utilities used to determine PGE's authorized ROE in UE 115. (*See* PGE Exhibit 100 Lesh/2 and PGE Exhibit 600 Hager/2 and 19).

Q. DOES PGE QUANTIFY THE LEVEL OF HYDRO RISK MITIGATION THAT THE HGA MUST PROVIDE IN ORDER TO RETURN THE COMPANY'S CURRENT RISK PROFILE TO ITS HISTORIC RISK PROFILE?

A. No.

Q. DOES PGE SUGGEST THAT THE COMPANY AND CUSTOMERS WOULD BE BETTER SERVED IF PGE MANAGEMENT FOCUSED LESS ON RESPONDING TO THE FINANCIAL IMPACTS OF VARYING HYDRO CONDITIONS?

A. Yes. PGE witness Lesh states:

> The HGA contributes to incentives for good management over the long term by significantly mitigating the financial distraction of water conditions, over which PGE's management has no control. With the HGA, it is more likely that management's efforts will drive financial results than the current circumstances, in which it is most likely that water conditions drive financial results.

Q. DOES PGE SUGGEST THAT THE CURRENT NVPC MODELING (I.E. AVERAGE HYDRO POWER COST MODELING) IS BIASED?

A. Yes. PGE witnesses Niman and Tinker testify that the current practice of setting rates on the basis of Average Hydro Energy Power Cost, holding thermal plant dispatch constant, always results in under-recovery of power costs. PGE Exhibit 300 Niman – Tinker/ 26. They later testify that PGE can accept this bias against investors given the small deadband of the HGA mechanism. PGE Exhibit 300 Niman – Tinker/ 32. Also see PGE Exhibit 100 Lesh/4.

Q. DOES PGE INDICATE THE CRITERIA THAT INFLUENCED THE DESIGN OF THE HGA MECHANISM?

A. Yes. PGE witness Lesh indicates that PGE designed the HGA with the following criteria in mind:

1. Rate stability and predictability;

2. Transparency; and
3. Incentive for good management.

PGE designed the HGA mechanism with a balancing account, a $20 million amortization threshold, and a suggested three-year amortization period to provide the opportunity to promote rate stability and predictability. PGE designed the HGA mechanism to use simple calculations, verifiable market index prices, and deadband symmetry in order to promote transparent regulatory implementation. Finally, PGE designed the HGA mechanism with a $2.5 million deadband to provide the incentive for good management. (See PGE Exhibit 100 Lesh/15-16).

Staff Analysis of PGE's Hydro Generation Adjustment Proposal

Q. DO YOU AGREE WITH PGE WITNESS LOBDELL'S CONCLUSION THAT THE WHOLESALE MARKET FROM WHICH PGE BUYS REPLACEMENT POWER IN POOR HYDRO YEARS IS HIGHER PRICED AND MORE VOLATILE THAN IN THE PAST?

A. Yes. The current and expected future price level for the Mid-Columbia and California-Oregon Board market hubs are clearly higher than the price levels that prevailed in the mid-1990s.

Q. DO YOU AGREE WITH PGE WITNESS LESH'S STATEMENT THAT THE INCREASED EARNINGS RISK ASSOCIATED WITH HYDRO PRODUCTION WARRANTS CONSIDERATION IN THIS DOCKET?

A. Yes. PGE's relative risk position in the capital market and its resulting cost of capital are a fundamental regulatory issue. As we indicated in UM 1071, staff believes the use of a reasonably structured automatic adjustment clause is preferable to the periodic use of deferred accounting.

Q. DO YOU AGREE WITH PGE'S CHARACTERIZATION THAT THE RATEMAKING RESPONSE IS AN EITHER/ OR CHOICE BETWEEN RAISING ROE AND MITIGATING HYDRO RISK?

A. No. Staff witness Conway stresses the importance of a comprehensive evaluation of PGE's overall risk. Considering changes in the wholesale power markets in isolation from changes in capital structure, interest rates, and the tax code is insufficient for determining whether the currently authorized ROE is adequate. Staff Exhibit/ 200 Conway/7. Mr. Conway also emphasizes that increased risk does not always translate in into an increase in the ROE an investor requires. A prudent investor may be able to diversify away all, or a portion, of the increased risk. Staff Exhibit/ 200 Conway/4.

Q. DO YOU AGREE WITH THE CHARACTERIZATION THAT AN AUTOMATIC ADJUSTMENT CLAUSE REDUCES RISK?

A. Yes, from PGE's perspective. However, an automatic adjustment clause does not reduce overall risk. It allocates risk between shareholders and customers. An automatic adjustment clause transfers risk previously borne by investors to customers. Whenever the company, staff, or any other party uses the phrase "risk reduction" to describe the effect of an automatic adjustment clause, they are viewing the risk from the company's perspective. From the customers' perspective, the NVPC risk is increased. Even if the expected value of the mechanism is zero, customers face more risk because they are exposed to significant swings in rates.

Q. DO YOU AGREE WITH PGE THAT AN AUTOMATIC ADJUSTMENT CLAUSE SHOULD BE USED TO ADDRESS HYDRO-RELATED EARNINGS RISK?

A. Yes. Staff believes the best response to the identified problem is to use an automatic adjustment clause to address a portion of the hydro-related earnings risk, while leaving a significant amount of that risk with the company. It is much more efficient to have the financial market diversify NVPC risk, than to allocate the risk to customers and have them bear it.

Q. DO YOU AGREE WITH PGE THAT THE REMOVAL OF THE FINANCIAL DISTRACTION OF VARYING WATER CONDITIONS SHOULD BE COUNTED AS A BENEFIT OF THE HGA MECHANISM?

A. No. Staff believes the company and customers are better served by keeping management focused on the financial risk associated with hydro resources. Staff believes that in order to meet the reasonable risk reduction criterion an automatic adjustment clause must continue to provide management incentive to actively manage the financial impacts of varying output from hydroelectric resources. Timely surplus sales during high hydro, timely replacement purchases during low hydro, and periodic searches for third party arrangements to hedge hydro risk are examples of prudent management.

Q. DO YOU AGREE WITH PGE THAT THE CURRENT NVPC MODELING (I.E. AVERAGE HYDRO POWER COST MODELING) IS BIASED?

A. No. The results of the Niman and Tinker illustrations depend on two problematic assumptions. First, the illustrations hold thermal plant dispatch constant. Second, price volatility is limited to power price volatility associated with hydroelectric generation. These constraints are not binding in the real world, the magnitude and direction of the any real bias is largely unknown. On one hand, allowing thermal plant dispatch to change with hydro-induced electricity price excursions would tend to mitigate the magnitude of the identified bias. On the other hand, a more complete stochastic spark spread analysis could indicate that the bias runs in the opposite direction.

Q. SHOULD THE COMMISSION USE THE SMALL DEADBAND OF THE HGA MECHANISM TO MITIGATE THE PERCEPTION OF BIAS IN CURRENT NVPC MODELING?

A. No.

Q. HAS STAFF IDENTIFIED ADDITIONAL DESIGN CRITERIA THAT SHOULD BE USED IN CONSTRUCTING AND EVALUATING AUTOMATIC ADJUSTMENT CLAUSES?

A. Yes. Staff adds three criteria to PGE's list of design criteria. First, staff believes a PCA mechanism should be designed to provide a reasonable amount of risk reduction or earnings stability for the utility. Second, staff believes the PCA mechanism should provide risk reduction and earnings stability without biasing the overall expected level of power cost recovery. Third, the Commission should ensure any proposal does not incent direct-access eligible customers on their choice to go direct access or remain with the company.

Q. PLEASE ELABORATE ON THE REASONABLE RISK REDUCTION CRITERION.

A. The fundamental issue in this docket is the amount of hydro risk reduction, or conversely earnings stability, that is reasonable to achieve through implementation of a HGA mechanism. It is important to recognize that an HGA mechanism is not the only tool available to the Commission. The Commission has traditionally addressed earnings risk when setting ROE. More recently, annual changes in PGE's energy rates through the RVM have likely smoothed PGE's earnings. These tools are not mutually exclusive and their use should be coordinated. In other words, the level of risk reduction to achieve through an HGA mechanism depends on the level of risk mitigation provided by the RVM and the level of risk compensation to be provided through ROE. Staff has consistently argued in recent cases that a PCA mechanism should be used to protect the company from extreme fluctuations in NVPC. (*See* Staff Testimony in Docket UE 137 and Staff Closing Comments in Docket UM 1071). Staff believes an extreme event PCA is a reasonable way to mitigate PGE's NVPC-related earnings risk. A large deadband serves several purposes. First, it serves to keep PGE focused on managing the financial impacts of varying hydro conditions. Staff believes PGE is better positioned to manage hydro-related financial risk through wholesale market activities than are customers through response to annual price signals. Second, a large deadband serves to keep supplemental ratemaking, such as a PCA, from becoming the primary form of ratemaking. Supplemental ratemaking should complement normalized test year ratemaking, not supplant it. Staff posits that a deadband that leaves the company with all of the NVPC risk except for plus and minus the projected outer most ten percent of NVPC distribution achieves these goals.

Q. DOES PGE'S PROPOSED HGA MECHANISM SATISFY THE REASONABLE RISK REDUCTION CRITERION?

A. No. PGE's HGA mechanism includes a symmetric deadband of $2.5 million. Beyond the deadband, customers would cover one-hundred percent of any deviation from the average hydro generation included in rates. A $2.5 million deadband shifts nearly all of PGE's hydro-related risk to customers. Eliminating nearly all hydro risk is unreasonable and overshoots PGE's stated goal of bringing hydro-related earnings risk back in-line with its historic risk profile. PGE has historically been a bearer of hydro risk and should retain a significant portion of this risk. If the Commission were persuaded by the company's testimony, at a minimum, there should be a sharing of the value of hydro excursions, between customers and the company, outside of the deadband.

Q. PLEASE ELABORATE ON THE NEUTRAL COST RECOVERY CRITERION.

A. The goal of normalized test year ratemaking is to allow the company to recover its costs on an expected basis, no more, no less. The regulatory goal remains unchanged when normalized test year ratemaking is supplemented with an automatic adjustment clause. The use of an automatic adjustment clause should not result in an expected economic windfall to the utility or to its customers.

Q. DOES PGE'S PROPOSED HGA MECHANISM SATISFY THE NEUTRAL COST RECOVERY CRITERION?

A. No. The symmetric HGA deadband is likely to create an expected value windfall for PGE. PGE witness Lobdell has testified that the costs of replacement power in poor hydro years outweigh the benefits of additional power in good hydro years. PGE Exhibit 200 Lobdell/2. A symmetrically designed HGA mechanism that tracks the asymmetric financial impacts of hydro variability can be expected to produce a balancing account balance that favors PGE.

Q. PLEASE ELABORATE ON THE EQUAL TREATMENT CRITERION.

The Commission shall ensure the provision of direct access to some retail electricity consumers does not cause unwarranted shifting of costs to other retail electricity consumers of the utility. ORS 757.607(1). The Commission may use transition charges or transition credits to reasonably balance the interests of retail electricity consumers and utility investors. ORS 757.607(2). Staff believes that the underlying intent of ORS 757.607 is to provide the direct access option without providing preferential treatment for any particular class of consumers or the utilities investors. The goal of equal treatment should be extended to supplemental ratemaking. The Commission should ensure any proposal does not incent direct-access eligible customers on their choice to go direct access or remain with the company.

Q. DOES PGE'S PROPOSED HGA MECHANISM SATISFY THE EQUAL TREATMENT CRITERION?

A. Yes, but not in a totally satisfactory manner. PGE proposes to apply the HGA adjustment rate in a prospective manner to all customers except to those customers who have chosen direct access for the five-year minimum term. PGE suggests that it does not make sense to guarantee the output of hydro resources for the opt-out customers. PGE Exhibit 700 Kuns/3. In a strict sense this satisfies the equal treatment criterion. However, it does so at the expense of the direct access program and market based rate options. Direct access provides non-residential customers the potential to obtain a fixed energy price from an Energy Service Supplier (ESS). Applying the HGA rate to direct access customers eliminates the potential for a fixed rate. Market-based rate options provide non-residential customers the ability to obtain market-indexed rates from the utility. Applying the HGA rate to these customers eliminates this possibility. In other words, the HGA adjustment rate would eliminate the potential benefits of these programs.

Q. SHOULD THE COMMISSION REJECT PGE'S HGA PROPOSAL?

A. Yes. PGE's HGA proposal fails to satisfy important automatic adjustment clause criteria.

Staff's Long Term PCA

Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATION FOR ADDRESSING THE INCREASED EARNINGS RISK ASSOCIATED WITH PGE'S HYDROELECTRIC GENERATION.

A. Staff recommends that PGE use Expected Value Power Cost modeling in its next general rate case. This modeling should be used to jointly determine the NVPC component of PGE's revenue requirement and the deadband parameters of an extreme event PCA mechanism. Staff's recommended solution has the following attributes:

1. PGE should file a PCA tariff that tracks, for extreme excursions only, the annual difference between actual cost-of-service NVPC and the forecast cost-of-service NVPC included in rates.
2. The definition of NVPC should be broadened to include natural gas sales for resale.
3. The PCA deadband should be set: (1) to exclude a reasonable range of normal variation from triggering the PCA mechanism, and (2) to be neutral on an expected recovery basis. For example, a deadband set at the 10th and 90th percentiles of the NVPC distribution would satisfy these criteria.
4. Annual amounts falling outside the deadband should be shared ten percent to PGE and ninety percent to customers. Ninety percent of all amounts exceeding the deadband would be placed in a balancing account for later amortization.
5. The PCA rate should be calculated using a one-year amortization period and the balance collected from, or paid to, customers over the subsequent year.

6. The PCA rate should be applied to all customers that were charged cost-of-service rates during the PCA year.
7. The forecast cost-of-service NVPC and the PCA deadband should be reset annually via the RVM process.

Q. WHY DOES STAFF RECOMMEND EXPECTED VALUE POWER COST MODELING?

A. Staff recommends Expected Value Power Cost modeling for two reasons. First, Expected Value Power Cost modeling can provide for a more realistic simulation of PGE's system operations. It can provide a realistic representation of the variability, and any interactions, associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability. Second, Expected Value Power Cost modeling provides a distribution of NVPC that can be used to design a PCA mechanism that satisfies the reasonable risk reduction and expected value recovery criteria. In addition, Expected Value Power Cost modeling would remove any bias associated with Average Hydro Power Cost modeling (see PGE Exhibit 300 Niman – Tinker/ 24-26 and PGE Exhibit 301) and capture the extrinsic value (see PGE Exhibit 300 Niman – Tinker/ 26-29) of PGE's Beaver plant (including Beaver 8) and capacity tolling contracts. Essentially, Expected Value Power Cost modeling takes advantage of information and relationships currently not incorporated in PGE's power cost modeling. This information will improve estimation of NVPC and assessment of NVPC risk.

Q. DOES SIMPLY SWITCHING TO EXPECTED VALUE POWER COST MODELING OBVIATE THE NEED FOR A SUPPLEMENTAL AUTOMATIC ADJUSTMENT CLAUSE?

A. No. Expected Value Power Cost modeling does not represent a ratemaking response for treating the volatility of power costs around the baseline forecast. In other words, it does not address the earnings risk associated with power cost variability. Staff believes a properly designed PCA mechanism can be a reasonable means to mitigate PGE's earnings risk posed by large NVPC excursions.

Q. WHY DOES STAFF RECOMMEND A NVPC PCA INSTEAD OF A HYDRO-ONLY ADJUSTMENT MECHANISM?

A. PGE operates its hydro resources as an integrated part of it overall supply portfolio. The company manages its resource portfolio to be in approximate load-resource balance on an expected hydro basis. If hydro output is less than expected PGE rebalances its overall position by increasing thermal resource output and/or making market purchases. If hydro output is greater than expected PGE rebalances its overall position by decreasing thermal resource output and/or making market sales. PGE manages its overall supply portfolio to minimize power costs. It is important to capture the complex, often offsetting interaction of resources within the supply portfolio when setting supplemental adjustment rates. Ignoring thermal plant optionality in the design of a hydro-only adjustment mechanism produces an economic windfall to the utility. The best way to address this issue is to use a PCA mechanism that tracks all the components of NVPC.

Q. WHY DOES STAFF RECOMMEND INCLUDING NATURAL GAS SALES FOR RESALE IN THE DEFINITION OF NVPC?

A. Natural gas sales for resale are part of the complex interaction of system resources. Natural gas purchased in advance to support expected thermal resource dispatch is often sold when expectations change. For example, if hydro output is greater than expected, then natural gas-fired resources may be backed-down and the fuel resold in the wholesale market. In the past, these resale revenues have been addressed in ratemaking as part of Other Revenue. The Other Revenue component of PGE's revenue requirement has remained fixed since the last general rate case (Docket UE 115). Staff recommends updating the revenues associated with natural gas sales for resale annually through the RVM process and capturing them in any authorized automatic adjustment clause.

Q. WHY DOES STAFF RECOMMEND AN ANNUAL UPDATE OF THE PCA DEADBAND?

A. The annual deadband update is intended to address the single-snapshot, or next-year-only, problem. A power cost forecast represents a snapshot taken at a particular point in time. The snapshot reflects the conditions and constraints known at that point in time. The validity of the snapshot depends upon the stability of the conditions and constraints. In other words, a power cost forecast is only valid for as long as the conditions and constraints remain unchanged. PGE emphasizes this point when it argues that the annual RVM simulates the next year only, does not simulate any year beyond the RVM, and does not simulate the next 59 years into the future. PGE Exhibit 300 Niman-Tinker/17-20 and 29-30. PGE lists the following conditions and constraints as being susceptible to change over time:

- Hydro-system non-power constraints (for example, fish flows)
- Hydro-resource ownership shares (for example, Mid-Columbia contracts)
- Hydro-plant performance (for example natural degradation and plant upgrades)
- Hydro-plant decommissioning (for example Bull Run)

- Climatic cycles (for example a shift in streamflow distributions)
- Distributions and correlations between important economic variables (for example hydro/market price relationship)

How frequently these conditions and constraints change is open to debate. However, designing an annual deadband update into the PCA process allows parties to debate the stability of these conditions and is superior to a static deadband that could produce economic windfalls for the utility or its customers.

Q. WHY DOES STAFF RECOMMEND SETTING THE PCA DEADBAND: (1) TO EXCLUDE MOST OF THE RANGE OF NORMAL VARIATION FROM TRIGGERING THE PCA MECHANISM, AND (2) TO BE NEUTRAL ON AN EXPECTED RECOVERY BASIS?

A. First, staff believes that the purpose of a PCA is to protect the utility from excessive financial impacts associated with power cost variability. The PCA deadband should serve to exclude a reasonable range of normal variation from triggering the mechanism. For example, a PCA with a deadband set at the 10^{th} and 90^{th} percentiles of the NVPC distribution can be expected, on average, to provide supplemental ratemaking in 1 out of every 5 years. We note that the Commission indicated in Order 04-108 that a 1 in 4.5 year hydro event was not extraordinary enough to warrant deferred accounting. Supplemental ratemaking should complement normalized test year ratemaking, not supplant it. A large deadband also serves to keep PGE focused on managing the financial impacts of varying hydro conditions.

Second, staff believes a PCA should allocate risk without creating economic windfalls for the company or its customers. Setting base energy rates using Expected Value Power Cost modeling provides an equal risk of over-collecting or under-collecting NVPC in rates. Any asymmetries in the distribution of NVPC outcomes should also be reflected in the PCA deadband. It may turn out to be the case that the lowest ten percent of NVPC outcomes fall closer the distribution average than the highest ten percent of NVPC outcomes. Expected Value Power Cost modeling represents a "fair roll of the dice." The PCA deadband should be set to preserve this neutrality.

Finally, as indicated in Staff's Closing Comments in Docket UM 1071, we believe a one-sided PCA that covers excursions beyond the 80th percentile of the NVPC distribution is also reasonable. The one-sided PCA approach, however, requires that the NVPC included in base energy rates be calculated as the average of a truncated, or one-tailed, distribution. That is, rates would be set on an expected power cost that is lower than the average of the entire distribution. The company is compensated for this through having the PCA trigger only when NVPC are well above expected levels. When power costs are lower than expected, no sharing would take place. In the interest of transparency and simplicity staff recommends a two-sided PCA.

Q. WHY DOES STAFF RECOMMEND DEFERRAL OF NINETY PERCENT OF ALL AMOUNTS EXCEEDING THE DEADBAND?

A. Staff recommends amounts falling outside the deadband be shared ninety percent to customers and ten percent to PGE. Keeping a small percentage of NVPC risk with the company aligns the company and customer interests to minimize NVPC.

Q. WHY DOES STAFF RECOMMEND APPLYING THE PCA RATE TO ALL COST-OF-SERVICE CUSTOMERS WHILE EXCLUDING ALL DIRECT ACCESS AND MARKET BASED RATE CUSTOMERS?

A. Direct access provides non-residential customers the potential to obtain a fixed energy price from an ESS. Applying the PCA rate to direct access customers eliminates the potential for a fixed rate. Market-based rate options provide non-residential customers the ability to obtain market-indexed rates from the utility. Applying the PCA rate to these customers eliminates this possibility. The ability of the customer to disconnect their annual energy expense from regulated cost-of-service ratemaking is the primary benefit of these options. Applying a PCA adjustment rate to the programs eliminates the benefit.

Q. DOES STAFF'S PCA PROPOSAL SATISFY THE IMPORTANT DESIGN CRITERIA?

A. Yes. The large deadband satisfies the rate stability, incentive for good management, and reasonable risk reduction criteria. The potential for an asymmetric deadband, and the annual deadband update, satisfy the neutral cost recovery criterion. Although staff's PCA proposal does not provide equal treatment for cost-of-service and opt-out customers in all instances, the large deadband should provide equality in most years. Only when there are extreme NVPC excursions would these customer groups be treated differently.

<u>Expected Value Power Cost Modeling</u>

Q. ARE THERE INSTANCES WHERE EXPECTED VALUE POWER COST MODELING HAS BEEN USED IN PROCEEDINGS BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON?

A. Yes. PacifiCorp first used stochastic modeling of NVPC in its 2003 Integrated Resource Plan (IRP, Docket LC 31). The Commission in Order No. 03-508 acknowledged PacifiCorp's 2003 IRP. PacifiCorp refined its stochastic modeling for its 2004 IRP (Docket LC 39). PacifiCorp filed its Draft 2004 Integrated Resource Plan with the Commission on January 20, 2005. PacifiCorp has modeled the uncertainty associated with retail loads, natural gas prices, electricity prices, hydroelectric generation, and thermal unit availability. Stochastic model runs that vary all of these parameters are referred to as 'All-in' analysis. Model runs that vary only natural gas and electricity prices are referred to as 'Spark Spread' analysis. PacifiCorp's Draft 2004 IRP can be located on PacifiCorp's web site (www.pacificorp.com). Relevant sections include: Chapter 4: Risks and Uncertainties (pp. 61-69); Chapter 8: Results (pp. 138-154); and Appendix G: Risk Assessment Modeling Methodology.

Q. ARE THERE INSTANCES WHERE PGE HAS USED 'SPARK SPREAD' ANALYSIS IN A PROCEEDING BEFORE THE COMMISSION?

A. Yes. PGE used 'Spark Spread' analysis in its 2002 IRP (Docket LC 33) and its 2003 Request for Proposals for Power Supply Resources (Docket UM 1080). The Commission in Order No. 04-375 acknowledged PGE's 2002 IRP. Relevant sections of PGE's 2002 IRP Final Action Plan (March 2004) include: Description of Stochastic Modeling (pp. 73-74) and Appendix 3 - Price Forecast and Stochastic Modeling. Relevant sections of PGE's 2002 IRP Supplement (February 2003) include: Gas Prices for Capacity Tolling (p. 60) and Introduction of Volatility in Prices (pp. 61-63). Relevant sections of PGE's 2002 IRP (August 2002) include: Chapter 3: Evaluation Approach and Appendix M - Use of Stochastic Electric Prices in Our Plan.

Q. IS IT APPROPRIATE TO TRANSFER THESE STOCHASTIC MODELING TECHNIQUES FROM THE RESOURCE PLANNING ARENA TO THE RATEMAKING ARENA?

A. Yes. The elements that PacifiCorp has modeled stochastically for purposes of IRP are the same elements that have traditionally been, and currently are, normalized in the determination of test year revenue requirements. Portfolio risk is an important consideration in both resource planning and ratemaking. In each arena, sound decision-making requires the best possible measurement and assessment of the relevant portfolio risks. In the IRP arena, the company and Commission evaluate the risks associated with alternative portfolios comprised of existing resources and resource additions. The goal is to select the least-cost and least-risk resource portfolio. In the ratemaking arena, the company and Commission need to consider the risks of the existing resource portfolio and evaluate alternative forms of regulation. The goal is to select ratemaking methods that allocate risk fairly and provide the company with the opportunity to earn the allowed rate-of-return. Staff recommends that the Commission employ a consistent approach when considering portfolio risk. It is inconsistent to use sophisticated risk modeling when making IRP decisions, only to revert to point-estimate modeling when making ratemaking decisions.

Q. DOES STAFF RECOMMEND THAT PGE USE AN ‘ALL-IN’ ANALYSIS IN ITS NEXT GENERAL RATE CASE?

A. Yes. Staff agrees with PGE that the validity of Expected Value Power Cost modeling depends on developing a broad risk analysis. PGE Exhibit 300 Niman – Tinker/ 23. Staff’s recommended approach for estimating expected NVPC achieves an important consistency between the resource planning and ratemaking processes.

Q. ACCORDING TO PGE THERE ARE SIGNIFICANT BARRIERS TO IMPLEMENTING EXPECTED VALUE POWER COST MODELING IN MONET, PLEASE DISCUSS THESE BARRIERS?

A. Niman and Tinker list six barriers to implementing Expected Value Power Cost Modeling in MONET:

1. Defining correlations between variables.
2. Calibrating model results to actual results.
3. Modeling complexities of the WECC.
4. Modeling market responses outside of standard economic responses (e.g. 2000-01 California Power Crisis).
5. Long model run times.
6. Reconciling fundamentals simulations with the use of trading curves. PGE Exhibit 300 Niman-Tinker/ 31.

Staff does not consider the listed items to be significant barriers. Staff is recommending a modeling approach that dispatches PGE's system against natural gas and electricity prices derived from forward trading curves and a set of volatilities and correlations developed from historical price data. Electricity prices are developed exogenously and input into the model. Staff is not recommending modeling that requires fundamentals-based dispatch of the entire WECC to derive competitive market clearing electricity prices. With staff's recommended approach barriers 3 and 6 are overcome. Estimating volatility and correlation parameters for important electricity market drivers is challenging. However, both PacifiCorp and PGE have overcome this challenge in past IRP. Barrier 1 is not insurmountable. Staff is not recommending the modeling of scenario risks. The 2000-01 California Power Crisis was a scenario event, not a stochastic event.

Staff does not recommend modeling market responses outside of standard historical responses. Barrier 4 is avoided. Calibrating model results to actual results is an on-going challenge for both deterministic and stochastic modeling. Barrier 2 is a not specific to Expected Value Power Cost modeling. Finally, long model run times may be an issue. On the other hand, IRP modeling covers a twenty year planning horizon, whereas test year modeling covers a single year. Finally, there may be real barriers to incorporating stochastic modeling into spreadsheet-based models such as MONET. PGE may have to acquire or develop new production cost software. Two examples of such software are Global Decision Energy's Planning and Risk software and Power Cost Inc.'s GenTrader software.

Q. DOES PGE SUGGEST THAT THE 70-YEAR HISTORICAL STREAMFLOW RECORD IS AN INADEQUATE REPRESENTATION OF HYDRO VARIABILITY ON A GOING FORWARD BASIS?

A. Yes. PGE witness Mote identifies two shortcomings of using 70 years of historic streamflow data to simulate future streamflows. First, a reconstruction of Columbia River streamflow at The Dalles for the period 1750 to 1987 using tree ring data suggests that flow during the 20th century was less variable than flow during the 19th century. According to the reconstruction, the last 70 years does not include either the driest or wettest periods in the last 250 years. PGE Exhibit 402. Second, according to Mote, the slow steady rise of Northwest temperature over the 20th century is very likely the result of the growing human contribution to atmospheric greenhouse gases. Simulations of future Northwest hydrology, based on reasonable projections of future increases in greenhouse gases, suggest thirty to sixty percent decreases in Columbia River streamflow by mid-century.

Q. DO PACIFICORP AND IDAHO POWER USE STREAMFLOW DATA FROM THE SAME HISTORIC PERIOD TO NORMALIZE THEIR POWER COSTS?

A. Yes. It is interesting to note that PacifiCorp does not model a relationship between hydro conditions and market electricity prices. Idaho Power has modeled a hydro/electricity price relationship.

Q. DOES PGE RECOMMEND A NEW APPROACH TO MODELING STREAMFLOW ON A GOING FORWARD BASIS?

A. No. PGE witnesses Niman and Tinker recommend the continued use of the 70 years of historic streamflow data as an input to Average Hydro Power Cost modeling. PGE Exhibit 300, Niman – Tinker /32.

Q. DOES STAFF BELIEVE THAT THE HISTORICAL STREAMFLOW RECORD CAN BE USED TO DEVELOP STOCHASTIC POWER COST MODELING?

A. Yes. In addition, staff is willing to assess whether the 70 years of historic streamflow data continues to be appropriate given the potential weather-related impacts of the growing human contribution to atmospheric greenhouse gases.

<u>Staff's Interim PCA Proposal</u>

Q. PLEASE SUMMARIZE STAFF'S INTERIM PCA PROPOSAL.

A. Staff recommends an interim PCA for calendar years 2005 and 2006 with the following attributes:

1. PGE should file a PCA tariff that tracks the annual difference between actual cost-of-service NVPC and the forecast cost-of-service NVPC included in rates.

2. The definition of NVPC should be broadened to include natural gas sales for resale.
3. The PCA deadband should be set at plus and minus 250 basis points of ROE (approximately $40 million) from the forecast cost-of-service NVPC.
4. The amount falling outside the deadband should be shared ninety percent to customers and ten percent to PGE. Ninety percent of all amounts exceeding the deadband should be placed in a balancing account for later amortization.
5. The PCA rate should be calculated using a one-year amortization period and the balance collected from, or paid to, customers during the following calendar year.
6. The PCA rate should be applied to all customers that were charged cost-of-service rates during the PCA year.

Q. WHY DOES STAFF RECOMMEND A SYMMETRIC DEADBAND EQUAL TO 250 BASIS POINTS OF ROE?

A. The Commission established a deadband of 250 basis points of ROE around PacifiCorp's baseline NVPC in Docket UM 995. The Commission approved the same deadband around PGE's baseline NVPC in Docket UM 1008/UM 1009 and Idaho Power's baseline NVPC in Docket UM 1007. The Commission also used 250 basis points of ROE to benchmark the financial impact of poor hydro in Docket UM 1071. Without an explicit quantification of PGE's power cost variability we do not have sufficient information to recommend an asymmetric deadband.

Q. DOES THE COMMISSION HAVE THE ABILITY TO APPLY STAFF'S INTERIM PCA TO CALENDAR YEAR 2005?

A. Yes. PGE filed an application for deferral of costs and benefits due to hydro generation variance on December 30, 2004 (Docket UM 1187). PGE indicated in its initial application that it intended to capture the any hydro generation variance in 2005 for rate treatment pursuant to the outcome of UE 165. As we indicated in our Staff Report in this docket, presented at the July 6, 2004 Commission Public Meeting, the Department of Justice has indicated that the Commission has the discretion to authorize deferred accounting retroactive to the deferral application date, but it is not required to do so. The UM 1187 application provides the Commission options with respect to the date at which benefits and costs associated with PGE's proposed HGA mechanism are eligible for deferral. Staff believes the Commission also has the discretion to modify the balancing account formula to track positive or negative NVPC variance during 2005.

Q. WHY DOES STAFF RECOMMEND THAT ITS INTERIM PCA MECHANISM BE APPLIED TO BOTH CALENDAR YEARS 2005 AND 2006?

A. Staff recommends the interim PCA as part of a long-term commitment to the fair allocation of NVPC risk. Staff's interim PCA bridges the gap until a long-term PCA can be implemented. We believe it is important to maintain this long-term focus. Without further examination of the facts underlying Docket UM 1187, staff is unsure if the 2005 hydro variance warrants deferred accounting on a one-time stand-alone basis. However, we have already noted the similarity between our interim PCA and the Commission's use of 250 basis points of ROE to benchmark the financial impact of poor hydro in Order 04-108.

Q. WHY DOES STAFF RECOMMEND THAT PGE'S COST-OF-SERVICE NVPC BE USED AS THE PCA BASELINE?

A. The PCA baseline should reflect the NVPC included in cost-of-service rates. The PCA should track differences between actual costs and those included in base rates. This prevents economic windfalls associated with the placement of the PCA baseline.

Q. DOES THE FINAL MONET FORECAST OF NVPC IN PGE'S ANNUAL RVM PROCESS REFLECT PGE'S COST-OF-SERVICE NVPC?

A. No. The final MONET forecast includes the direct access and market based rate customer's share of PGE's long-term resources. Two adjustments are needed to calculate PGE's cost-of-service NVPC. First, the direct access and market based rate customer's share of wheeling expense must be removed from the MONET forecast. Second, the direct access and market based rate customer's share of PGE's long term resources must be re-priced at market and not included at cost. Staff Exhibit 102 shows these adjustments for the final MONET forecast in the 2005 RVM.

Q. WHY SHOULD THE DIRECT ACCESS AND MARKET BASED RATE CUSTOMER SHARE OF WHEELING EXPENSE BE REMOVED FROM THE MONET FORECAST?

A. The direct access customers presumably pay their ESS for wheeling expense. PGE's market based rate customers pay wheeling expense as part of the energy price under Schedule 83.

Q. WHY SHOULD THE DIRECT ACCESS AND MARKET BASED RATE CUSTOMERS' SHARE OF PGE'S LONG-TERM RESOURCES BE RE-PRICED AT MARKET?

A. All of PGE's long-term resources are reflected in the final MONET forecast at cost. However, PGE plans to use the opt-out customers' share of PGE's long-term resources to serve non-residential cost-of-service customers. The transfer of these long-term resources from the direct access and market based rate customers to the non-residential customers occurs at final forward market prices. In other words, PGE maintains an open price position in the non-residential resource stack to accommodate the transfer of long-term resources from opt-out customers to non-residential cost-of-service customers. Whenever the expected average variable cost of PGE's long-term resources is below the expected average forward market price, the final MONET forecast will understate PGE's cost-of-service NVPC. (*See* the Staff Report regarding Docket UE 161 presented at the December 21, 2004 Commission Public Meeting for a discussion of this issue.)

Q. DOES PGE RECOVER MORE THAN THE FINAL MONET FORECAST OF NVPC IN RATES?

A. Yes, whenever the average variable cost of PGE's long-term resources is below forward market prices. Staff Exhibit 102 shows that 2005 cost-of-service NVPC exceeds final MONET forecast NVPC by $32.6 million. The point being made is that the final MONET forecast of NVPC does not accurately reflect the NVPC included in cost-of-service rates and should not be used to set the baseline for a PCA.

Q. DOES PGE CURRENTLY OVER-COLLECT NVPC IN RATES?

A. No. The two cost-of-service adjustments described above are accurately accounted for when calculating the long-term resource transition adjustment for non-residential customers. All of PGE's cost-of-service customers pay cost-of-service rates through the combination of market based energy rates and long-term and short-term resource transition adjustments.

Q. HOW DOES PGE'S PROPOSED HGA MECHANISM ADDRESS THE TRANSFER OF THE OPT-OUT CUSTOMERS' SHARE OF LONG-TERM RESOURCES?

A. In effect, PGE avoids the issue of the allocation of its long-term resources by applying the HGA rate to all customers who receive the long-term resource transition adjustment (i.e. the Schedule 125 Part A rate). In other words, PGE avoids the issue by applying the HGA mechanism to all but the five-year minimum opt-out customers.

Q. IF THE COMMISSION MODIFIES PGE'S HGA PROPOSAL TO APPLY THE HGA RATE ONLY TO COST-OF-SERVICE CUSTOMERS, THEN SHOULD THE COMMISSION ALSO ADJUST THE BASELINE LEVEL OF HYDRO GENERATION INCLUDED IN THE HGA MECHANISM?

A. Yes. The baseline level of hydro generation would need to be reduced by an amount equal to the opt-out customers' share of PGE's hydro resources.

Q. THIS RVM RESOURCE ALLOCATION ISSUE IS COMPLEX, PLEASE LIST YOUR RECOMMENDATIONS RELATED TO THIS ISSUE.

A. First, I recommend that the Commission require PGE to begin calculating cost-of-service NVPC as part of its annual RVM filings. Second, I recommend that the Commission use cost-of-service NVPC as the baseline in staff's interim PCA. Finally, I recommend that the Commission consider the issue of whether PGE should continue to plan to use the opt-out customers' share of PGE's long-term resources to serve non-residential cost-of-service customers in PGE's next general rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME:	Maury Galbraith
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Energy Division
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2551
EDUCATION:	Graduate Student in Environmental Studies Program (1995 – 1997) University of Montana Missoula, Montana Master of Arts in Economics (1992) Washington State University Pullman, Washington Bachelor of Science in Economics (1989) University of Oregon Eugene, Oregon
EXPERIENCE:	The Public Utility Commission of Oregon has employed me since April 2000. My primary responsibility is to provide expert analysis of issues related to power supply in the regulation of electric utility rates. From April 1998 through March 2000 I was a Research Specialist with the State of Washington Office of the Administrator for the Courts in Olympia, Washington. From April 1993 through August 1995 I was a Safety Economist with the Pacific Institute for Research and Evaluation in Bethesda, Maryland.

Cost-of-service Adjustments to Final MONET NVPC

2005 RVM Final MONET NVPC[1]	$491,304,000
Remove Opt-Out Wheeling[2]	- 5,038,000
Sub-Total	$486,266,000
Re-price Opt-Out Share of Long-term Resource[3]	- 37,685,000
Estimated Cost-of-service NVPC	$523,951,000
Estimated Cost-of-Service NVPC – MONET NVPC	$32,647,000

[1] PGE Advice No. 04-19 filed November 15, 2004, Appendix 2, Attachment 1.
[2] PGE Advice No. 04-19 filed November 15, 2004, Appendix 2, Attachment 2. See: Stk111504-PUC-2005RL.xls 'CostOut' worksheet.
[3] Re-price Adjustment = ((Average Annual Forward Price – Average Annual Cost of PGE Long-term Resources) * (141 MWa Opt-Out Customer Share of PGE Long-term Resources) * (8,760 hours)).

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Bryan Conway. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC) as the Program Manager of the Economic and Policy Analysis Section in the Economic Research and Financial Analysis Division.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. My Witness Qualifications Statement is found on Exhibit Staff/201, Conway/1.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I rebut the testimony of Company witnesses Dr. Makholm and Mr. Hager.

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes. I prepared Staff/201, consisting of one page and Staff/202, consisting of 22 pages.

PGE's Required Rate of Return

Q. WHAT IS PGE'S REQUIRED RATE OF RETURN?

A. Generally speaking, PGE's required rate of return is that return that is required to attract investors. PGE's overall rate of return can be considered as the return to debt holders (cost of debt), the return to preferred stock holders (cost of preferred) and the return to equity holders (cost of equity).

Q. WHICH PORTION OF THE RATE OF RETURN DOES PGE SEEM MOST CONCERNED WITH?

A. PGE appears to focus most of its attention on its cost of equity. Specifically, PGE claims its currently authorized return on equity is insufficient. (*See* UE-165, PGE/500, Makholm/4 lines 1-3, Makholm/5 lines 13-15, Makholm/22 lines 15-18.)

Q. HOW DOES PGE DETERMINE ITS CURRENT RETURN ON EQUITY IS INSUFFICIENT?

A. PGE compares the level of hydro risk it believes it faces to that of the group of comparable companies used in PGE's last rate case, UE 115.

Q. WHEN WAS THE ORDER ISSUED IN UE 115?

A. Order 01-777 was issued on August 31, 2001.

Q. WHAT RETURN ON EQUITY WAS AUTHORIZED IN ORDER 01-777?

A. The Commission authorized a return on equity of 10.50 percent.

Q. IF ONE WERE TO ASSUME THAT THE COMPARABLE COMPANIES WERE STILL THE CORRECT SET TO USE FOR DETERMINING PGE'S

COST OF EQUITY, COULD YOU SIMPLY ADJUST THE RETURN ON EQUITY RECOMMENDATION IN UE 115 UPWARDS TO REFLECT INCREASED HYDRO RISKS?

A. No. Just as PGE's actual return on equity varies over time, so do the returns on equity of the comparable companies. At a minimum, the data on PGE and the comparable companies should be updated to reflect more recent information.

Q. IS IT APPROPRIATE TO COMPARE PGE'S HYDRO RISK TO A SNAPSHOT OF COMPARABLE COMPANIES FROM UE 115 TO DETERMINE IF PGE'S CURRENT AUTHORIZED RETURN ON EQUITY IS SUFFICIENT?

A. No. The determination of PGE's required return on equity is not as simple as tracking changes in risks at PGE to a snapshot of comparable companies from its last rate case. As discussed in Order 01-777,

> "[t]he task of determining a reasonable ROE, however, is often one of the most difficult and contentious aspects of a rate case proceeding. This docket was no different. PGE and Staff presented ROE testimony from seven witnesses and submitted over 600 pages of prefiled testimony and supporting documents. They required two full days of hearing on the ROE issue, at which they introduced approximately 30 new exhibits. After hearing, PGE and Staff produced over 100 pages of legal argument on the issue, and spent a majority of their time at oral argument addressing the issue to the Commission."

Q. WHAT DOES PGE CONCLUDE REGARDING THE COMPARABLE COMPANIES FROM UE 115?

A. PGE concludes that the comparable companies from UE 115 are no longer valid. (*See* PGE/600, Hager/19 lines 14-15.)

Q. DID PGE PERFORM AN ANALYSIS OF ITS CURRENT REQUIRED RETURN ON EQUITY?

A. No. PGE performed no such analysis. (*See* Staff/202, Conway/1-7 - PGE's response to Staff Data requests 5, 6, 7, 8, and ICNU data requests 19, 20, and 22.)

Q. AT PGE/600, HAGER/19, LINES 5-6, MR. HAGER STATES THAT THE ROE DETERMINATION IN UE 115 DID A REASONABLE JOB OF COMPENSATING PGE'S INVESTORS FOR THE RISKS THEY FACED, INCLUDING HYDRO RISK. DO YOU AGREE?

A. Yes. I believe the Commission authorized an ROE that adequately compensated PGE's investors.

Q. AT PGE/600, HAGER/19, LINES 6-15, MR. HAGER STATES THAT DUE TO REVISED PERCEPTIONS OF HYDRO RISK AND THE ABSENCE OF A COMPREHENSIVE PCA, PGE'S REQUIRED ROE IS HIGHER—OTHER FACTORS BEING THE SAME—THAN THAT AUTHORIZED IN UE 115. PLEASE COMMENT.

A. In general, I would accept that increased hydro risks and the loss of a comprehensive PCA may, in isolation, increase PGE's riskiness. However, as the Modern Portfolio Theory points out, this increased risk may not translate into an increase in the ROE an investor requires. This is because a prudent investor may be able to diversify away all or a portion of these risks and therefore, would not require additional compensation. PGE acknowledges as much in its response to ICNU data request 22, where it states that a prudent investor could minimize exposure to risks posed by hydro conditions but state that it is unclear how much of the hydro risk can be diversified away. (*See* Staff/202, Conway/7.)

Q. PLEASE DESCRIBE THE MODERN PORTFOLIO THEORY.

A. Modern Portfolio Theory relates to an investment approach that tries to construct a portfolio offering maximum expected returns for a given level of risk tolerance. The theory assumes that investors like investment returns but dislike the risk, or volatility, associated with those returns. By purchasing assets in portfolios investors reduce the total variation of their returns. The result is that investors require a lower return for bearing less risk.

The total variation of a portfolio is less than the sum of its parts because in a diversified portfolio of risky assets some returns are high while others are low, offsetting each other. A common example that has been proffered in testimony to the Commission follows: Stock A (a suntan lotion company) and stock B (an umbrella company) are both expected to earn 10 percent and have equivalent risk. However, it seems that returns on the two stocks move in exactly opposite directions. When it is sunny, stock A makes unusually good returns but stock B makes unusually poor returns. When it is rainy, stock B makes unusually good returns and stock A makes unusually poor returns. Combining the two stocks in a portfolio allows all risk to be diversified away, even though each of the companies' returns is still quite risky independently.[1] The risk that can be diversified away becomes irrelevant and investors do not require a return on this diversifiable risk.

Modern finance theory indicates that most well diversified investors are concerned with non-diversifiable (market) risks when considering their return on equity. These market-oriented risks include such things as interest rate changes, threat of war, and recession. They differ from diversifiable risks in that the latter are company-specific and relate, for instance, to the factors that impact only the company or its market segment.

In other words, when we speak of diversification, we are talking about owning a complement of investments. Dividing investment funds among a variety of securities with different risk and reward relationships is presumed to be the major concern of any sophisticated investor. The primary reason is that the investor can reduce or completely "diversify away" unsystematic, or "company-specific" risk and only have exposure to systematic, or "market" risk.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR. HAGER'S TESTIMONY AT PGE/600, HAGER/19, LINES 6-15?

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[1] More precisely, assuming that the variance of returns of companies A and B are the same, the portfolio of them together has the variance: σ2(A) + σ2(B) + 2ρ(A,B)σ(A)σ(B). If ρ(A,B) = -1(the securities' returns are perfectly negatively correlated), and σ(A) = σ(B),then the portfolio variance equals 0.

A. Yes. Mr. Hager concludes that PGE's required ROE is "*higher—other factors being the same—than that authorized in UE 115 and that the sample of utilities is not valid.*" (*See* PGE/600 Hager/19, lines 13-15, emphasis added) In this statement, Mr. Hager uses a common assumption in economics known as "ceteris paribus." By assuming all other factors affecting PGE's ROE remained constant, Mr. Hager's statement cannot be interpreted as concluding that PGE's currently authorized ROE of 10.5% is inadequate either with or without hydro risk.

Q. WHAT OTHER FACTORS HAVE CHANGED THAT MIGHT AFFECT THE ROE REQUIRED BY PGE'S INVESTORS?

A. Not much has remained constant. PGE's capital structure has become more equity rich[2], interest rates have fallen[3], and tax code changes have made high-dividend paying companies more attractive[4], just to name a few. Unless these and other pertinent factors are taken into account, there is no valid basis for a conclusion that PGE's currently authorized ROE of 10.5% is not adequate. In a nutshell, no one in this docket has made the case that the currently authorized ROE is insufficient either with or without an HGA mechanism.

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[2] In part, because PGE has not been paying dividends to Enron, the percentage of equity in PGE's capital structure has risen from 52.16% (Order 01-777) to 57.52% as of 9/30/2004 (See Staff/202, Conway/8). Using the logic contained in Order No. 01-777, this increased equity would result in another reduction in ROE of approximately 15-20 basis points, all else being equal.

[3] From August 24, 2001 to January 21, 2005, interest rates on 3-, 5-, and 7-year Treasuries have fallen by 62, 83, and 85 basis points respectively. (*See* Conway/202, page 9.)

[4] *See* Conway/202, pages 10-22.

Conclusion

Q. WHAT HAS STAFF CONCLUDED REGARDING THE COST OF EQUITY ISSUES RAISED BY PGE?

A. PGE's cost of equity testimony does not demonstrate that PGE's current ROE is inadequate even taking into account hydro risks. Additionally, the most appropriate venue for determining PGE's cost of equity is in its next general rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME: Bryan A. Conway

EMPLOYER: Public Utility Commission of Oregon

TITLE: Program Manager, Economic & Policy Analysis Section

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION:

B.S. University of Oregon, Eugene, Oregon
Major: Economics; 1991

M.S. Oregon State University, Corvallis, Oregon
Major: Economics; 1994

In addition, I have completed all of the required and elective coursework for a Ph.D. in economics from Oregon State University. My fields of study were Industrial Organization and Applied Econometrics.

EXPERIENCE:

Starting in October 1998, I have been employed by the Public Utility Commission of Oregon. I am currently the Program Manager of the Economic & Policy Analysis Section. My responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. I have testified before the Commission on policy and technical issues in UG 132, UE 115, UE 116, and have been the Summary Staff Witness in UP 158, UP 168, UP 165/170, UX 27, UX 28, UM 967, UM 1041, UM 1045, and UM 1121.

From December 1994 to October 1998, I worked for the Oregon Employment Department as a Research Analyst in their Research Section. Duties included leading research projects on various policy issues involving labor economics and information systems.

OTHER EXPERIENCE:

I am currently a faculty member of the University of Phoenix teaching economics.

From January 1998 through September 2000, I was a part time instructor at Linn-Benton Community College teaching principles of economics.

From July 1992 through June 1994, I was a graduate teaching assistant at Oregon State University teaching introductory principles of economics.

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CERTIFICATE OF SERVICE

UE 165

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by mailing a copy properly addressed with first class postage prepaid to all parties or attorneys of parties.

Dated at Salem, Oregon, this 14th day of February, 2005.

David B. Hatton

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