BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

2006 RVM
UE-172

PORTLAND GENERAL ELECTRIC COMPANY

REBUTTAL TESTIMONY OF

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I. Introduction

Q. Please state your name and position at PGE.

A. My name is James F. Lobdell, and my position is Vice President of Power Operations. My qualifications appear at the end of this testimony.

My name is Mike Niman. I am Manager of the Financial Analysis Department. My qualifications were previously provided in PGE Exhibit 100.

My name is Patrick G. Hager, and my position is Manager, Regulatory Affairs. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to rebut several proposed adjustments to PGE's power cost forecast for 2006:

- Some parties suggest removing the 2006 planned Sullivan Plant outage because PGE scheduled it (and included it) in the 2005 RVM. We show that the circumstances that prevented PGE from performing this work in 2005 were beyond PGE's control, the variance is just one of many occurring this year, and such unintended variances are not reasons to alter a forecast of what will happen.
- Some parties propose to exclude costs for PGE's capacity tolling agreements from the 2006 RVM. We show that these cost-effective capacity tolling agreements provide customers with valuable reliability services and are properly included in the RVM.
- Some parties propose to reverse PGE's correction to Mid-C hydro capacities because they believe it is a modeling change that is not permitted under the stipulation adopted in UE-149. ICNU also questions PGE's modeling of hydro plants for meeting operating

reserve requirements. We provide a detailed description of the correction to Mid-C hydro capacities to show that it is not an enhancement or modeling change and therefore permitted by the RVM stipulation. We also explain how PGE meets its operating reserve requirements in the most efficient manner possible and that Monet models our power costs to match our actual operations.

- ICNU proposes an adjustment for the four 2001 contracts addressed in the 2004 and 2005 RVMs (UE-149 and UE-161). We demonstrate that the four contracts are effectively removed from 2006 power costs at a small profit, so that customers are benefited, not harmed. We also explain how ICNU's assumptions surrounding the four contracts are illogical and inconsistent, and would result in higher NVPC for the 2006 RVM than currently estimated.
- CUB questions the use of PGE's forward curve in determining power costs for the RVM by noting that "There is a great deal of money at stake in the forward electricity price curve, yet it is currently impossible to challenge PGE's forward price curve" (CUB/100, Jenks/9). We address this concern by demonstrating that when the final RVM estimate is prepared in mid-November, large changes in the forward curve have relatively small effects on PGE's RVM costs. Further, we show that the results can be counterintuitive, making it very difficult to "game" the forward curve.

In addition, we update PGE's retail load and power cost forecasts based on more recent information. The result of the updated load forecast is a decrease in total system load of approximately 36 aMW for 2006. The current power cost forecast has a $6.8 million decrease from the June 10 update (and $6.9 million decrease from the original April 1 filing), for a total of $636.8 million in NVPC.

II. Planned Sullivan Outage

Q. Some parties maintain that because a planned Sullivan outage was included in the 2005 RVM, it should be excluded from the 2006 RVM. Do you agree with this view?

A. No. We have not, in prior RVMs, trued-up differences between forecast and actual planned outages. As discussed below, forecast outages are always different from actual outages, either in timing or duration or both. Additionally, while it is true that the 2005 planned outage of Sullivan has not occurred, the circumstances that caused it to be delayed in 2005 have been resolved and it is now planned in 2006.

Q. Why are there differences between planned outages forecast in the RVM and what actually occurs?

A. PGE prepares inputs for the Monet model and its RVM forecasts with the most current and best information available. However, plant parameters for the RVM, such as planned outages, must be estimated by March 1 of the preceding year to be included in the April 1 filing (per Commission Order 02-772, which was in response to other parties' concerns regarding the scope and timing of RVM-related changes to Monet). This is as much as a year to a year-and-a-half before a planned outage will actually occur. Consequently, the dates and length of planned maintenance outages are unlikely to match perfectly those forecasted. These deviations in planned maintenance outages can have positive or negative effects on PGE's power cost.

Q. How significant have these deviations been in recent years?

A. For thermal plants, the deviations by outage day for 2003 and 2004 are listed in PGE Exhibit 301. In most instances, the actual planned outages exceed the forecasted planned outages.

For most of PGE's hydro plants the deviations are not significant because we schedule planned maintenance to coincide with discretionary shutdowns during low-water flow months to minimize lost generation. However, the Sullivan plant deviations have been significant because of the nature of the work and the fact that it is a run-of-river plant. Consequently, the 2005/2006 planned outages necessitate a complete shut-down of the plant.

Q. Has Sullivan had planned outages that were not included in an RVM?

A. Yes. In 2004, Sullivan was completely shut down from mid-June through October for environmental work which involved repairing the head gates so the plant could be isolated from the river. In addition, PGE built a "training" wall, a structure that directs the water flow to Unit 13, which is screened to protect fish in downstream passage.

Q. Did PGE seek to recover the 2004 outage in a subsequent RVM?

A. No. PGE uses only forward projections of planned outages and we do not incorporate historical errors into the forecast. By April 1, the deadline for establishing planned outages in an RVM, PGE's forecast is directed toward next year's requirements and not on outages that have yet to transpire in the current year.

Q. Was the 2004 planned outage necessary?

A. Yes. The outage was necessary so PGE could perform subsequent environmental work such as the construction of a new fish migration structure. This environmental work is part of PGE's commitment for the Sullivan operating license.

Q. In the 2005 RVM, when did PGE plan to perform the subsequent environmental work?

A. In our April 1, 2004 filing, we expected the Sullivan plant to be shut down from July through October 2005. Based on the information available at that time, we expected to be able to complete all environmental studies, obtain permits, etc. in time for the July 2005 outage.

Q. Did PGE plan to perform other maintenance work during the outage?

A. Yes. During the 2005 environmental work outage, PGE planned to perform two additional jobs that would also require Sullivan to be completely shut down:

- Major electrical work on generators, switches, and relocation of transformers.
- Installation of a screen cleaner and repairing the runner on the 13^{th} turbine.

Q. Did PGE perform the 2005 Sullivan outage as planned?

A. No. Several issues arose by February 2005 that precluded the July 2005 planned outage and required PGE to postpone it until 2006. First, NOAA Fisheries (National Oceanic and Atmospheric Administration; formerly NMFS, National Marine Fisheries Service) did not issue its biological opinion report. This report would confirm PGE's proposed environmental work. Second, the FERC did not issue the necessary operating license. These two documents would allow PGE to file for an in-river permit from the Army Corps of Engineers and to prepare for the outage. Because PGE did not receive the biological opinion and license by February 2005, our timetable for the 2005 outage was not feasible and PGE was forced to move the planned environmental outage to 2006.

Q. Will PGE perform a planned outage at Sullivan in 2005?

A Yes. PGE has planned a seven-day outage to perform work on the switch yard that could not be deferred for safety reasons.

Q. Were these circumstances beyond PGE's control?

A. Yes. It was not prudent for PGE to proceed with several components of the fish passage facilities without the necessary permits, agency reviews, or license.

Q. What are your conclusions regarding the proposed Sullivan adjustment?

A. The Sullivan outages represented significant challenges on PGE's oldest and most unique hydro plant. As a result, PGE has experienced both positive and negative deviations from the planned outages included in RVMs. Ultimately, we conclude that the proposed adjustment is not appropriate given the circumstances surrounding the outage.

Q. What are your conclusions regarding the treatment of planned outages in general?

A. Excluding the Sullivan and Beaver plants, PGE's experience with determining planned outages has been fairly accurate and we propose no change to the current method for rate-setting processes. The Commission could, however, determine that an historical average for planned outages should be used in PGE's RVM. If so, we believe that the average should be used in the next RVM in order to allow consistent treatment of all generating plants.

III. Capacity Tolling Agreements

Q. Some parties argue that costs for the capacity tolling agreements should be excluded from the 2006 RVM because they allege that there are no corresponding benefits. Do you agree with this position?

A. No, for at least five reasons.

- PGE purchased these capacity tolling agreements as part of a balanced, diversified resource portfolio in the context of PGE's most recent long-term Integrated Resource Plan (IRP). The IRP was acknowledged by the Commission.
- The capacity tolling agreements are a cost-effective way to provide necessary capacity when it is required.
- The capacity tolling agreements are more than financial hedges and they benefit customers.
- Long-term resources such as the capacity tolling agreements should not be viewed in isolation on the basis of short-term incremental economics.
- These agreements are capacity resources and capacity resources have been included in PGE's retail rates for decades.

1. Prudent Acquisitions per the IRP

Q. Your first reason is that the capacity tolling agreements were included in PGE's long-term IRP. Please describe the IRP as it relates to capacity issues.

A. The IRP is a lengthy process in which PGE identifies how it plans to meet its long-term resource requirements. The IRP also describes our approach to balance the need to reliably supply our customers against costs for resources. The IRP calls for us to meet loads in all

8760 hours of the year, plus both operating reserves (6%) and an additional "planning" or contingency reserve of 6%, under normal water and weather conditions. We fill all but the last 500 MW of this capacity requirement through supply actions approximately 18 to 24 months or more in advance of the anticipated need. We then seek to fill the last 500 MW of this target with purchases made within the shorter-term market. The last 500 MW happens to be slightly in excess of the operating and contingency reserve margin targets. Thus, in practice, we fill only to our actual expected retail customer demand need with longer-term committed resources and then fill the reserve requirement position in the nearer-term market.

Q. How does this approach compare to other utilities?

A. Other utilities tend to be more conservative regarding capacity/reliability. For example, some plan to 70% hydro availability or "critical water" standards. Others plan to 1-in-5 weather conditions, rather than 1-in-2 conditions used in PGE's plan. Still others plan to a 15% or higher reserve margin.

Q. What exactly is capacity as opposed to energy?

A. These terms are usually used in the context of the capability of a generating plant to supply power as required by the end users. Capacity is a measure of the use or supply of power at a given moment in time, and is measured in megawatts (MW) or kilowatts (kW). Energy is a measure of use or supply over time, and is expressed in megawatt-hours (MWh) or kilowatt hours (kWh). To illustrate the difference, assume a constant customer load of 500 MW (i.e., 500 aMW) that might, at first glance, be met by a coal plant rated at 500 MW capacity. Although the plant has a maximum capacity of 500 MW, the average energy from the coal plant over time will generally be lower due to both planned and unplanned outages, as well as temporary power de-ratings. Consequently, while customer load will total 4,380,000 MWh for the year (500 MW x 8760 hours in a year), the coal plant will not generate that much energy because outages and de-rations will lead to lower than maximum capacity for some periods of time.

Uncertain generation from generating plants (as illustrated above), in conjunction with uncertain load requirements from customers (largely driven by deviations from "normal" temperatures and changing operations of our industrial customers) are reasons why additional peaking supplies are required to assure reliable power supply. Utilities help assure this reliability by maintaining a mandated level of operating reserve (spinning reserves and other actions that can be taken within ten minutes) of 5% of on-line hydro generation plus 7% of on-line thermal generation (for long-term planning purposes estimated at 6% of load in our most recent IRP), and an additional planning reserve (usually 6% or greater).

Q. What is the appropriate capacity position?

A. There is no one right answer to this question because the answer depends on a host of factors such as:

- The overall regional loads versus supply balance.
- The degree of congestion in the transmission system to move power from remote generation resources to PGE's load.
- The cost and depth of the wholesale market.
- The native utility's resource mix.

This issue has been and will continue to be a subject of discussion among regulatory agencies throughout the U.S.

Q. Did the Commission acknowledge PGE's approach in your recently concluded IRP?

A. Yes. The Commission, in Order No. 04-375, acknowledged PGE's acquisition of 955 MW of capacity resources[1] beyond what PGE's owned and contracted energy resources could be expected to provide under normal operating conditions.

Q. Did the Commission express any concerns in their order with respect to filling PGE's capacity target?

A. No, they did not.

Q. Did other intervenor parties express concerns?

A. No. During the long process (and lengthy record), this was not a contentious topic.

Q. How did PGE implement the Commission's acknowledgement to acquire 400 MW of additional firm capacity resources?

A. PGE issued a request for proposals (RFP) and then negotiated with those bidders who offered the best terms and prices. The capacity tolling agreements now in place represent the lowest cost offers available in the marketplace for this kind of product.

2. Cost-Effective Measures

Q. Your second reason is that capacity tolling agreements are cost-effective measures to provide necessary capacity when it is required. What other alternatives were available to PGE and its customers?

A. We had a number of alternatives, which included one or more of the following:

- Seeking more demand-side response where available.

[1] 400 MW of the 955 MW would be from additional firm capacity resources.

- Bringing on more year-round energy resources.
- Relying more heavily on the spot markets to fill our position.
- Purchasing capacity agreements with lower heat rates.
- Purchasing capacity agreements of different types, e.g., our Washington Water Power Capacity Contract.
- Forcing customers to bear the costs of potential outages.

All of these alternatives are more expensive and/or more risky than the capacity tolling agreements. For instance, over-reliance on the short-term market, while sometimes the least expensive approach, can result in periods, such as during the 2001 energy crisis, where scarcity can result in lack of availability or extraordinarily high prices. Moreover, this is a strategy that could cause severe problems if adopted widely. To prevent this, many regions are considering minimum planning reserve requirements for each load-serving entity. At the same time, acquisition of lower heat-rate capacity or energy resources that produce higher dispatch rates in power cost modeling would be much more expensive and would result in incurring costs during periods where the additional capacity is not needed.

Q. How did PGE include demand-response options in its evaluation of alternatives?

A. We issued a request for qualifications (RFQ) for demand response in conjunction with our supply-side RFP.

Q. Please summarize the purpose and results of the demand-response RFQ.

A. PGE believed that one of the best alternatives to making commitments to additional supply-side resources was to gauge the willingness of our customers to curtail demand if paid to do so. We sent the RFQ to 86 of our largest customers. We kept the requirements very broad to encourage participation and creative responses. However, we received only one response, for a small amount of megawatts, and at far more expensive prices than the supply-side alternatives.

Q. What did PGE conclude from this RFQ?

A. We concluded that, in general, our customers place a high value on reliability. It is often less expensive to provide reliability through supply-side measures than through demand-response programs. This is not to say that demand-response programs will not work. Rather, this speaks to the difficulty of developing programs that will work for individual customers while delivering benefits to the system as a whole. We are continuing to investigate and evaluate future demand-response options.

Q. Could PGE have provided reliable capacity for a lower cost than the capacity tolling agreements?

A. No. PGE executed the best deals available in the market place. Because these contracts are for only the winter months, they are less expensive than acquiring year-round capacity. The contracts are also priced lower than the price for which our customers are willing to curtail their use.

Q. Why couldn't PGE just purchase energy in the short-term market if the need arises?

A. This is a risky strategy from a reliability point of view. These capacity contracts are meant to bridge the gap during high load and constrained capacity times. Without them, there is the real possibility of service disruptions.

Q. Do you have any recent examples of supply constraints?

A. Yes. In fact, capacity and reliability were an issue this summer. Quoting from the July 25 *Clearing Up* article entitled "BPA Dodges Heat Wave Power-Reserve Bullet":

> "As temperatures climbed early last week, the BPA scrambled to buy power to cover its reserve margins and considered declaring a power emergency that would have curtailed Biop-mandated spill operations. Power managers decided to go to the market for 120 MW of capacity on Monday morning, *but got no response*. As a precaution, BPA called the Technical Management Team's river managers to alert them to the possibility that an emergency might be declared that would curtail all spill operations.
>
> The managers were able to avoid the emergency call and provide BPA with blocks of power totaling 1,200 MW for prices ranging from $75 to $130 per MWh, compared with recent prices of $50 per MWh." (Emphasis added.)

In other words, BPA came very close to stopping spill operations (required by federal regulations in support of the Endangered Species Act) in order to maintain service. PGE does not have such an option. In a similar situation, PGE would be preparing to shed load. The capacity contracts provide a much-needed cushion to help ensure continuity of service.

Q. Are you concerned that the capacity tolling agreements are not dispatched by Monet during 2006?

A. No. Monet models normal conditions rather than extreme conditions or events.[2] Thus, its logic will not dispatch the capacity tolling agreements under current market heat rates. Monet's output, however, will also not reflect all of the additional costs that would coincide with such extreme conditions. For example, non-dispatch of a capacity contract means lower costs for customers because they will not incur the cost of the commodity (energy) charge, which would be levied if the capacity contract were exercised.

Q. Could PGE have purchased capacity tolling agreements that would have dispatched in 2006?

A. Yes, but these tolling agreements would have had much lower heat rates to dispatch under the normal conditions and market heat rates in Monet. Because of the lower heat rates, the costs would be significantly higher than the existing agreements because such resources would require paying for high expected energy value as well as capacity value. Consequently, we believe that the existing agreements are an effective, low-cost way to supply needed capacity.

Q. Did PGE exercise these capacity contracts during the last winter season?

A. No. The 2004/2005 winter was mild and the contracts were not exercised. The next winter could also be mild, but it could also be normal or it could be severe. No one knows. But, we must plan for power to be available, even in severe weather. Hence, just because the contracts did not dispatch last winter does not imply they will not be required next winter. In addition, there has been a notable decline in capacity additions in the Pacific Northwest following the retrenchment of the IPP and merchant sectors in 2001 and 2002. This will likely result in tighter regional and WECC reserve margins as well as supply and demand balances in the future.

3. More Than Financial Hedges

Q. Your third reason is that PGE's contracts are not just financial hedges that solely benefit PGE stockholders. What type of contracts are they?

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[2] PGE's weather-adjusted load forecast includes at most a one-in-two peak weather condition for January and July of each year.

A. They are actual physical contracts that require the delivery of power to specific points on our system. When called upon, the counterparty to the capacity agreements will "settle" their obligation with actual power, not monetary payments. The difference between the financial and physical hedge is similar to the difference between fire insurance and the installation of actual fire suppression measures. Fire insurance is a financial hedge while fire suppression measures, such as ceiling sprinklers, are a physical hedge designed to provide safety.

Q. Is it prudent to have capacity resources and contracts in place?

A. Yes. If PGE does not acquire physical capacity resources in advance of peak energy needs, then we run the risk that capacity and energy will not be available in the market when we need it most. The situation is analogous to fire suppression measures. Just because none of our neighbors have recently experienced a fire does not imply that our buildings should not have sprinklers. Nor, once they are installed, should we claim that the sprinklers are a poor investment because there have been no fires. Likewise, the prudence of providing sufficient capacity to reliably meet our customers' power needs should not be in question.

4. Evaluation of Long-Term Resources

Q. Please elaborate on the fourth reason, which is the treatment of long-term resources.

A. Market heat rates change over time. Rate-setting policy should not be based on the short-term incremental economics of long-term resources, viewed in isolation. A balanced resource portfolio includes a variety of resource types: base load energy, peaking capacity, hydro plants, thermal plants with different heat rates, long-term and short term electric and fuel contracts, different fuel types, storage devices, renewable energy, demand-side management options, etc. Having a diversified, balanced resource portfolio is standard, prudent utility practice and a well-established method for reducing risk in portfolios of all types. It is not rational to pick and choose which resources should go into the power cost model based solely on the isolated, incremental, short-term economics of individual resources.

5. Consistent Treatment of Capacity Resources

Q. Your fifth reason suggests that the parties are being inconsistent in their proposal to exclude these agreements. Do you have any examples of other capacity agreements that have been included in rates?

A. Yes. In the past, PGE has included a number of various heat-rate-option-type resources as part of a balanced, diversified resource portfolio. These included the Bethel plant (approximately 12.5 DT/MWh heat rate), the Beaver Plant (approximately 9.5 DT/MWh heat rate), and Trojan replacement contract resources from the California / desert southwest area in the early 1990s with boiler-type heat rates (10-11 DT/MWh). These resources were all included in retail rates. Other types of resources have sometimes appeared uneconomic when viewed in isolation, such as the Washington Water Power Capacity Contract. This contract resource provides shaping, peaking capacity and reliability value, which may not be apparent in NVPC calculations, but are part of a prudent, balanced resource portfolio.

Q. What are your conclusions regarding the capacity tolling agreements?

A. The capacity tolling agreements are a prudent addition to PGE's resource mix as acknowledged by the Commission in PGE's most recent IRP. The agreements provide valuable reliability service for customers and should not be excluded from the RVM calculations.

IV. The Input Correction to Mid-C Hydro Capacities

Q. CUB and ICNU contend that the input correction is really an enhancement that is precluded by the stipulation in UE-149, the 2004 RVM proceeding. Do you agree with this assertion?

A. No. CUB and ICNU are incorrect. The update to the Mid-Columbia (Mid-C) hydro capacities we input to Monet is not a model enhancement, modeling change, or change to program logic and therefore not precluded by the stipulation. This input correction is no different than if PGE had incorrectly estimated the increased capacity after we performed the Boardman plant upgrade. That 2005 upgrade added approximately 21 MW to Boardman's capacity. Had we input the wrong capacity in Monet's parameters, all parties would have expected us to correct the error.

Q. What did you correct in Monet?

A. We corrected the capacities of the Mid-C resources to use realistic operating constraints.

Q. Why is a correction to the Mid-C inputs necessary?

A. Prior to the 2005 RVM, the Mid-C hydro capacities were not "critical" inputs because of the way hydro was modeled in Monet. In the Monet model, the simulated hourly hydro generation was the product of four factors: capacity, annual factor, monthly factor, and hourly factor. With four factors available, the hourly and monthly factors provided sufficient flexibility (i.e., degrees of freedom) for Monet to reflect the appropriate levels of hourly and monthly hydro energy. In this prior version, the annual factor and capacities could be any nonzero numbers – for example, the plant capacities could be set to 1 MW or 100,000 MW each – because PGE simply scaled the monthly or annual factors up or down as necessary to achieve the appropriate MW hourly and monthly energy output. Although the input Mid-C capacity did not present an issue by itself, we became aware that our overall modeling in Monet was substantially understating the amount of Mid-C output that could be generated in high-market-priced hours.

Q. What hydro change did you make in the 2005 RVM (OPUC Docket No. UE-161)?

A. As described in PGE's testimony in UE-161, we performed an enhancement, allowed under the UE-149 stipulation, to the hourly hydro dispatch algorithm in Monet to more accurately reflect the relationship between electric market prices and the discretionary dispatch of PGE's Mid-C hydro resources. PGE made this enhancement in response to comments by ICNU in UE-149 (see ICNU/100, RJF/5 and 22-31). The impact of the enhancement in UE-161 was to decrease NVPC by $4.7 million. However, with the enhancement, the Mid-C capacities became "critical" inputs. In other words, it made a difference whether plant capacities were set at 1 MW or 100,000 MW or the correct level.

Unfortunately, the Mid-C capacities being used by Monet's new logic were, by default, the capacities that had been originally input to the model approximately 10 years ago. These were inappropriate and incorrect in the context of the new hourly dispatch logic. Consequently, we realized that the model was substantially overstating the amount of Mid-C generation that could be put into the high-market-priced hours and that the capacities needed to be corrected.

Q. Why was this correction not included in the 2005 RVM?

A. We stated several times in UE-161 (for the 2005 RVM), that this input correction would be necessary because we did not have enough time by April 1, 2004 to verify all the parameters that calculated the capacities. For example, in workshops after the April 1, 2004 filing, we discussed the need to correct these parameters but, based on comments by other parties, we agreed to not make any corrections at that time to keep the 2005 RVM close to what we filed.

Q. What specifically did PGE correct in the 2006 RVM?

A. PGE updated the Mid-C capacities based on information received from Central (i.e., the entity housed within Grant County that manages the Mid-C hydro projects). We receive this information on an hourly basis and it reflects the maximum usable capacity available to PGE for dispatch from our share of the Mid-C projects. We then estimated the monthly average usable capacities and calculated a four-year average using 2001 through 2004 as a reasonable approximation of the actual capacity available to PGE for hourly dispatch of its Mid-C resources. This historical average represents the portion of the plant capacity that is operationally available to PGE for dispatch. It is less than the previous capacity, which was the sum of PGE's shares times the individual maximum one-hour capacities of each of the projects.

Q. Is this four-year average similar to the one PGE uses to de-rate its thermal plants?

A. Yes. The only difference is the number of factors included in the average. For PGE's Mid-C resources, the historical average includes all the factors that can reduce maximum capacity to usable capacity. For PGE's thermal plants, only forced outages are based on historical averages while de-rations from other components, such as planned outages, are included at forecasted levels. No parties claim that updates to these thermal plant capacity de-rations represent "modeling" changes.

Q. How do you respond to ICNU's claim that, after this correction, "Monet has a much lower maximum capacity and much higher minimum capacity than has occurred in practice" (ICNU/100, Falkenberg/19)?

A. ICNU is comparing apples-to-oranges, which will always produce deviations but not necessarily meaningful ones. There are several reasons why ICNU's comparison of 2004 actual operations to the 2006 forecast has little, if any, value:

- There are substantial differences between PGE ownership shares of Wells and Priest Rapids in 2004 versus 2006 due to the Colville Settlement by Douglas County PUD and our renewal of the Priest Rapids Contract.
- The self-provision of operating reserves on the Mid-C for PGE's various contract purchases is modeled in the 2006 RVM as reductions in the Mid-C usable capacities, while in 2004 we purchased these operating reserves from BPA, so there was no effect on our Mid-C operation.
- The volatility of actual hydro, load, and electric prices (2004) causes actual hydro hourly generation to be more volatile than it is modeled in Monet, which uses expected weather-adjusted loads, expected electric prices, and normalized hydro generation (2006).
- At times, most or all of a given Mid-C plant's units will be available (i.e., not scheduled or forced out of service). At other times, many units will be unavailable. This will tend to increase the variability of the observed 2004 actual hourly generation as compared with the 2006 *average*, *de-rated* Monet modeling. The same observation would apply to PGE's thermal units.

Q. Did you perform any other corrections to the Mid-C capacities?

A. Yes. We modified the four-year average to reflect recent reductions in capacity available to PGE from the Wells project due to the Douglas County PUD's settlement with the Colville Tribes.

Q. What are your conclusions about the corrections to the Mid-C capacities?

A. PGE performed an enhancement to Monet for the 2005 RVM filing and then corrected the input for Mid-C capacities in this RVM filing. The input correction to the 2006 RVM is not an enhancement, modeling change, or change in program logic and, therefore, is not precluded by the stipulation in UE-149. Further, PGE should not be penalized for failing to change these inputs in the 2005 RVM. The April 1, 2004 deadline for updates simply did not permit the analysis necessary to calculate the proper parameters. The Commission should allow this input correction in the 2006 RVM because it produces more accurate results – something we believe everyone would favor.

V. Modeling Reserves

Q. What are ICNU's concerns regarding the way PGE models operating reserves in Monet?

A. ICNU claims that PGE is not operating its system economically and that we incorrectly model operating reserves and regulating margins by carrying them only on hydro units rather than gas units. ICNU suggests that if PGE carried operating reserves on our thermal units, such as Beaver, we could free up the hydro units to generate a higher proportion of energy during peak hours and a lower proportion during off-peak hours. Effectively, ICNU is suggesting that PGE is not operating its resource portfolio to minimize power costs.

Q. Do you model your operating reserves accurately?

A. Yes. PGE's primary goal with Monet is to accurately reflect how PGE's system of power resources is actually operated so that we can reasonably forecast our NVPC. In actual operations, we carry our operating reserves at Mid-C and PGE hydro plants. This was explained in detail in the white paper provided in the 2005 RVM, entitled "Mid-Columbia Hydro Plant Hourly Dispatch Enhancement," dated April 27, 2004 (see PGE Exhibit 302). PGE does not carry any of its operating reserve requirements, either spinning or non-spinning, on its thermal units, including Beaver. In this sense, the modeling in Monet is consistent with how we actually operate our resources.

Q. Why do you carry operating reserves on just hydro plants?

A. PGE carries its operating reserves on its hydro plants for several reasons. The first reason is that, to provide spinning reserves, a unit needs to operate below capacity or at "part-load." In general, hydro units are much better suited to part-load operation because they are designed to ramp their generation up and down with generally less wear and tear than with thermal units. In contrast, thermal units prefer more steady-state or base-load operating conditions. This is why in the Pacific Northwest, with the large amount of installed hydro generating capacity, spinning reserves are generally carried on hydro units. For example, the Mid-Columbia Hourly Coordination Agreement operates the system of Mid-C hydro plants as though they were owned by a single utility. This maximizes the efficiency of operation in general, including the efficient distribution of spinning reserve requirements of the multiple participants among the system of coordinated Mid-C plants.

Q. What is the second reason that you carry operating reserves on hydro plants and not gas units?

A. The second reason is that, for providing standby operating reserves, hydro units are much better suited for a quick-start operation from a shutdown condition than thermal units. A unit classified as standby operating reserves must be capable of being on-line and generating within 10 minutes. PGE has no thermal units that can meet this requirement, including Beaver.

Q. Are there additional reasons to carry operating reserves on hydro plants and not gas units?

A. Yes. It would be very expensive to operate thermal units as reserves. To provide spinning reserves on a thermal unit, such as Beaver, requires part-load operation of that thermal unit. This would, however, incur a significant heat-rate penalty on the entire unit's generation, making the plant more expensive to operate. At the high price of natural gas we observe in the market today, this cost would be prohibitive.

Q. ICNU suggests that the Beaver generation logs indicate that PGE is operating Beaver at part-load much of the time and that we have the flexibility to provide reserves there. How do you respond?

A. In Monet, PGE models the Beaver plant to run at its full six-unit de-rated capacity when it is economic to do so based on the plant heat rate, burner-tip variable gas price, variable O&M, market electric price, and plant operating constraints (e.g., unit commitment logic). We de-rate Beaver's full six-unit capacity to reflect maintenance and forced outage rates, just as we do with other PGE plants. Thus, although Beaver's full monthly six-unit capacity might be 521 MW, we spread the outages over the month, reducing that maximum available capacity to something less.

In actual operations, Beaver may operate with only four or five of its six units running at capacity. One reason that we might not operate all units is that much of the time one unit is unavailable – it is either scheduled or forced out of service. Another reason is that real-time dispatch decisions include market considerations, generator ramp times, and on- and off-peak price spreads. In addition, gas purchases are made on a day-ahead basis, and it is risky to nominate gas for full six-unit operation on a given day as total plant generation (over 500 MW) could potentially swing the market price of power to the point where the plant became uneconomic. If this were to occur, we would have to sell gas within the day at a significantly lower price than we purchased.

While a casual review of the Beaver generation logs might suggest that we operate the individual Beaver units at part-load and possibly reserve some generation, our practice is to operate each of Beaver's thermal units at full load. As stated above, to operate a given

Beaver unit at part-load would incur a significant and costly heat rate penalty. To operate our system as ICNU suggests would likely result in a significantly higher NVPC.

Q. Do these same factors apply to regulating margins?

A. Yes. With respect to our thermal units, such as Beaver, for regulating margin, automatic generation control or load following, the same reasoning applies as discussed above for operating reserve. We do not use our thermal units for these purposes, and to do so would likely result in significantly higher NVPC.

Q. What do you conclude about PGE's operations regarding reserves and regulating margins?

A. We believe that PGE operates its system in the most efficient manner and that our power cost modeling reflects actual plant operations. ICNU appears to have misinterpreted Beaver's generating logs and their concerns are based on incorrect assumptions. We propose no changes to our plant operations or NVPC modeling based on these issues.

VI. Use of the Forward Curve

Q. CUB maintains that "There is a great deal of money at stake in the forward electricity price curve, yet it is currently impossible to challenge PGE's forward price curve" (CUB/100, Jenks/9). Hasn't this issue been addressed in prior proceedings?

A. Yes. PGE described the sources and use of the forward curve in UE-115 (see PGE/300, Pollock – Huntsinger/15-18) and UE-161 (see PGE/300, Nguyen – Niman – Hager/15-16). We have held workshops on forward curves, most recently on February 23, 2005, which CUB attended. We have also explained why PGE's forward price curve is preferable to other alternatives.

Q. How do you respond to CUB's claim that there is a great deal of money at stake in the forward electricity price curve?

A. As we observed in UE-161, "the potential impact of large movements may be material if PGE has a significant open position at the time prices are set. Otherwise, there is very little impact of changes in forward prices on net variable power costs" (PGE/300, Nguyen – Niman – Hager/15). Because PGE has a very small open position by the time we set prices in the final RVM run, we expect very little to be at stake in the forward electricity price curve.

Q. Have you performed an analysis to test your belief?

A. Yes. We took the final Monet run from the 2005 RVM and adjusted the forward electric curve by plus and minus 10 percent to test the effect on PGE's NVPC. The results are as follows:

Table 1
Effect of changing forward electric curve on NVPC

Case	NVPC ($000)	Delta ($000)
Base 2005 RVM	491,304	-
FC + 10%	486,780	- 4,524
FC - 10%	491,763	+ 459

With a 10% increase in the forward price curve, the result was actually a <u>decrease</u> in NVPC of $4.5 million or 0.9%. A 10% decrease to the forward price curve produced a $459,000 increase to NVPC or a 0.1% increase.

The asymmetric change in NVPC with electric forward curve price is due primarily to two factors:

- The change in electric forward curve prices relative to PGE's base-case electric open position:
  a) <u>If PGE's open position is short</u> and we purchase energy at market prices in Monet, an increase in the electric forward curve will increase NVPC, while a decrease in the electric forward curve will decrease NVPC.
  b) <u>If PGE's open position is long</u> and we sell energy at market prices in Monet, an increase in the electric forward curve will decrease NVPC, while a decrease in the electric forward curve will increase NVPC. Table 2 below summarizes the possible NVPC outcomes, all else equal.

Table 2
Effect on NVPC from changes in the electric forward curve relative to PGE's open electric position

	Forward Curve Price Increase	Forward Curve Price Decrease
Short Position	Increase NVPC	Decease NVPC
Long Position	Decrease NVPC	Increase NVPC

- The change in thermal plant dispatch in response to changing electric prices. For example, if electric prices increase, gas plant dispatch tends to increase, displacing more expensive electric market purchases with less expensive gas-fired generation, reducing NVPC. Conversely, if electric prices decrease, gas plant dispatch tends to decrease, displacing gas-fired generation with cheaper electric market purchases, again reducing NVPC. Table 3 summarizes these effects on NVPC, all else equal.

Table 3 – Effect on NVPC from changes in the electric forward curve relative to PGE's dispatchable plants.

	Forward Curve Price Increase	Forward Curve Price Decrease
Increase Dispatch	Decrease NVPC	N/A
Decrease Dispatch	N/A	Decrease NVPC

The asymmetry occurs because, as shown in Table 3, there are only potential NVPC decreases and not increases. In other words, the Table 3 decreases will either offset the increases in Table 2 or enhance the decreases in Table 2. Clearly, the relative (percent) change in power costs is much smaller than the relative (percent) change in the forward curve and in fact, can provide changes that are contrary in direction to the change in the curve. It, therefore, makes it very difficult to "game" the forward curve.

Q. What do you conclude about CUB's concerns regarding use of the forward curve in determining PGE's power cost forecast?

A. PGE believes the forward curve is still the best tool available for its intended purpose. We establish the forward curves without bias and do so as an input to (and hence prior to) the Monet model runs from which we determine our NVPC forecast. The table above shows that because we do not have a significant open position when final power costs for rates are determined, the effect of rather large changes to the forward curve does not involve "a great deal of money." Indeed, because the results are sometimes counterintuitive, it is difficult to "game" the forward curve. As we noted in UE-161, PGE does not believe that there is currently adequate reason for the Commission to abandon the use of PGE forward curves that have been used in rate setting proceedings during the last four years.

VII. The Four Contracts

Q. ICNU proposes a $7.2 million disallowance on four 2001 contracts with a combined total of 100 MW of flat energy for calendar years 2004 through 2006. Do you agree with this adjustment?

A. No. ICNU has no basis on which to propose this disallowance.

Q. Does PGE still hold those contract positions?

A. No. On May 17, 2004, PGE sold 25 MW of its position by selling flat energy for calendar year 2006 at $43.50 per MWh. On August 3, 2004, PGE sold the remaining 75 MW of its position for 2006, also for $43.50 per MWh.

Q. So PGE realized a gain on the sale of these four power purchase contracts?

A. Yes. Based on an average purchase price of $43.44/MWh, PGE realized a small gain of $54,750 when it sold its positions.

Q. Is that gain included in NVPC in this RVM proceeding?

A. Yes, the gain lowered NVPC by $54,750.

Q. Does ICNU have any basis to claim that the sale of the 100 MW position is completely independent of the original contracts?

A. No, just the opposite. PGE would not have sold 100 MW of flat energy for calendar year 2006 in May and August 2004 if it did not already have corresponding contract purchase positions. Doing so would have been speculation. PGE is a regulated utility with an obligation to serve its customer load, and insufficient generation resources to meet that load. As a result, PGE must purchase energy to meet its load virtually every hour of the year. For such a company to sell 100 MW of flat energy for an entire calendar year, 15 to 19 months before the start of delivery for the year without a corresponding purchase position would be speculative and greatly increase the exposure of the company and its customers to market price changes.

Q. But don't forward purchases expose the company and its customers to the financial effects of market price changes?

A. Not in the same way as a "naked" sale of forward power that is not backed up by either generation resources or power purchase contracts. Since PGE would need to purchase power to fill the sold position and also to meet the load of its customers, the exposure of PGE and its customers to market price changes would be multiplied.

Q. Does PGE regularly sell yearly flat energy products?

A. No, we do not. This was an unusual sale for PGE and would not have been done if PGE did not have a corresponding power purchase position to close out.

Q. Does ICNU identify which power contracts, presently in Monet, would support the sales of the 100 MW if not these four 2001 contracts?

A. No, they do not. As a consequence of ICNU's arguments, PGE would have to purchase 100 MW to offset these sales. At current market electric prices, this would increase power costs, which would be clearly imprudent and illogical.

Q. How do you respond to ICNU's allegation that PGE's efforts constitute turning an imprudent action into a prudent one?

A. First, PGE does not believe that these contracts were imprudent. Second, we simply recognize that even if it was imprudent to purchase these contracts, customers are not harmed in the 2006 RVM. ICNU's analysis is not based on the impact to customers, but rather advocates arbitrary punishment of utilities based on their view of alleged imprudent activities. That is not proper regulatory practice as we understand it. Prices for regulated utilities are set based on prudently incurred costs to provide service. The issue here is whether costs for customers have been increased by the alleged imprudent action. They have not. If an action claimed to be imprudent has not raised costs, there is no disallowance.

Q. So customers are not harmed in 2006 by the presence of these contracts?

A. No. As noted above, PGE has sold the contract positions for a small gain, and that gain has decreased net variable power costs in this RVM.

Q. How does ICNU propose to calculate a disallowance?

A. ICNU proposes to price the contracts as if all 100 MW were purchased at the price of the lowest contract.

Q. Is that consistent with ICNU's position in the previous RVM dockets?

A. Not entirely. In the 2004 RVM (UE-149), ICNU argued against this approach. Instead, they proposed to re-price the four contracts using market prices from 18 months prior to the calendar year (see ICNU/100, RJF/11). In the 2005 RVM (UE-161), ICNU cited the "UE-139 precedent" as a possible approach to re-pricing the contracts (see ICNU/100, RJF/12).

Q. Would the approach ICNU advocated in previous RVM dockets result in a disallowance?

A. Probably not, but it would depend on the specific date chosen to price the contracts. It is nevertheless a moot point because, for the 2006 RVM, PGE has actual sales of the contract positions – from 19 and 16 months prior to the start of the calendar year and for more than the contract purchase price. Using those prices would produce no disallowance.

Q. Do you agree with the approach ICNU advocates in this docket?

A. No. This approach does not develop a reasonable "but-for" world against which to measure the impact of imprudence. In using the lowest price of the four contracts as the proxy price for all the contracts, ICNU implies that it would have been prudent for PGE to purchase 100 MW of flat energy on one day in 2001, for delivery from 2004-2006. That assumes that PGE could have had perfect foresight. It also assumes that a transaction for 100 MW of flat energy could have been entered on that day. There is no evidence in this record that this was possible.

Q. Is ICNU's approach in this docket theoretically sound?

A. No. ICNU claims that PGE was imprudent in entering into all four 25 MW contracts. Yet ICNU would have the Commission assume that purchasing 100 MW on the same day and at the same price as one of the four allegedly imprudent contracts would have been prudent, and order a disallowance accordingly. That approach is paradoxical. Ultimately, because there is no harm to customers in the 2006 RVM from the four 2001 contracts (in fact there is a small gain), ICNU has no basis for any disallowance.

VIII. Load Forecast

Q. Has PGE updated its load forecast for 2006?

A. Yes. We re-estimated the model and load forecast for 2006 based on historical data through May 2005 and on the latest economic forecasts from the State of Oregon and Global Insight.

Q. What is the updated load forecast?

A. For 2006, total cycle loads at the meter are forecast at 19,253 million kWh, compared to 19,566 million kWh as provided in the prior forecast. Total cost of service loads have also been re-estimated at 18,252 million kWh for 2006, compared to 18,529 million kWh in the prior forecast.

Q. What are the drivers of the change in total system loads from the prior load forecast to the updated load forecast for 2006?

A. There are two drivers of the change in load forecast which is approximately 313 million kWh (36 aMW, or 1.6%) lower than our previous 2006 forecast:

- The first is reduced demand by residential and secondary customers. This decline appears to be a change in customer behavior in response to the increasing price of oil and other energy products. Year-to-date kWh deliveries have been lower than forecasted in the April 1 RVM filing and electricity use per residential customers is beginning to decline after increasing in both 2003 and 2004.
- The second is that two large non-residential customers have reduced their forecast of demand from PGE.

Q. Does PGE intend to update its forecast of loads prior to setting final rates in November?

A. Yes. The state will issue a new economic forecast on September 1. Our goal is to derive the most accurate estimate of loads possible for 2006. PGE intends to re-estimate that model later in the third quarter of the year for an updated forecast of economic activity, and to include additional actual usage data as well as any large customer's changes in operations. If the result of this update is a different load forecast than the one provided here, we will submit that load forecast for inclusion in calculating final rates in November.

IX. Updated Forecast of NVPC for 2006

Q. Has PGE developed an updated forecast of net variable power costs for 2006?

A. Yes. PGE Exhibit 304 provides a hard copy of the Monet output for the forecast. We have also provided electronic copies on CD to Staff, CUB, and ICNU.

Q. What is PGE's current forecast of NVPC for 2006?

A. We currently forecast $636.8 million of NVPC for 2006. This forecast reflects the current load forecast for Cost of Service customers and excludes any cost to serve Schedule 125, Part B opt-out loads who may either select a market-based pricing option under Schedule 83 or service from an ESS.

Q. How does the current forecast of NVPC for 2006 compare to other forecasts filed by PGE?

A. Our initial NVPC forecast filed April 1 totaled $643.7 million. The update that we filed on June 10 totaled $643.6 million. In dollar terms, the current forecast reflects a small decrease compared to those previously provided in this docket. The step log, included on the CD, shows the incremental updates we've made to Monet since the prior update filed on June 10.

Q. What is the remaining schedule for providing updates to NVPC in this docket?

A. On November 3, PGE will file another Monet update, locking down all inputs except forward curves and incorporating the impact of any Commission order(s) in this docket. On November 10, we will file the final Monet run with an update to forward curves for 2006. PGE posts final RVM prices pursuant to the final NVPC forecast on November 15, with an effective date of January 1, 2006.

X. Qualifications

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE in 1984, I have held a variety of positions at PGE and its affiliates including Vice President, Risk Management, Reporting, and Control; Vice President of Portland General Distribution Company; Vice President of Portland General Holdings II; Vice President of FirstPoint Utility Solutions; Manager of Financial Risk Management and Pricing at PGE; Treasurer of Tule Hub Services Company; Manager of Commercial Group Accounting for Portland General Holdings; Project Manager for Columbia Willamette Development Company; and Supervisor of Accounting Operations for Portland General Corporation. I entered my current position of PGE Vice President of Power Operations in September 2002.

Q. Mr. Hager, please summarize your qualifications.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs. I am responsible for determining PGE's revenue requirements as well as estimating PGE's Required Return on Equity.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
301	Thermal Plant Planned Outages
302-C	"Mid-Columbia Hydro Plant Hourly Dispatch Enhancement" white paper dated 4-27-04 (Confidential – separate envelope)
303	Delivery Forecast by Market Segment and Service Level
	Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
	Forecast of Residential Use per Occupied Account and Ultimate Deliveries
	Commercial Deliveries Forecast by NAICS Cluster
	Industrial Deliveries Forecast by NAICS Cluster
	Forecast of Deliveries under Miscellaneous Secondary Rate Schedules
	Forecast 2006 PGE Net (Cost-of-Service) and Opt-Out (Non-Cost-of-Service) Loads
304-C	Monet Output and Summary (Confidential – separate envelope)

Comparison of Planned and Actual Outages for PGE's Thermal Plants

		Planned Outages - Monet Forecast (days)					Actual Planned Outages (days)				
	Docket	Boardman	Colstrip 3	Colstrip 4	Coyote	Beaver	Boardman	Colstrip 3	Colstrip 4	Coyote	Beaver
2003	UE-139	30	0	58	28	28	29	0	56	35	75
2004	UE-149	69	44	0	0	17	72	49	0	4	38

G:\RATECASE\OPUC\DOCKETS\UE-172 2006 RVM\Testimony_Rebuttal_PGE\Exhibits\[Exhibit 301 - Thermal Plants Outages.xls]All PGE's Thermal Plants

Delivery Forecast by Market Segment and Service Level
(at normal weather)

	(in million kWh)				% Change[1]		
	2003	2004	2005	2006	2004	2005	2006
Schedule 7	7,196	7,433	7,470	7,627	3.3%	0.5%	2.1%
Residential Lighting et al	5	7[2]	7	7	26.8%	(0.0%)	(1.2%)
Total Residential	7,201	7,440	7,477	7,633	3.3%	0.5%	2.1%
Commercial[3]	6,580	6,761	6,866	7,064	2.7%	1.5%	2.9%
Manufacturing[3]	4,553	4,286	4,376	4,348	(5.9%)	2.1%	(0.6%)
Miscellaneous Customers	202	198	207	208	(1.7%)	4.2%	0.7%
Secondary Voltage[4]	6,942	7,194	7,304	7,533	3.6%	1.5%	3.1%
Total General Service	7,144	7,392	7,511	7,741	3.5%	1.6%	3.1%
Primary Voltage Service[5]	2,678	2,676	2,682	2,747	(0.1%)	0.2%	2.4%
Transmission Voltage Service[5]	1,514	1,178	1,256	1,132	(22.2%)	6.7%	(9.9%)
Total Retail	18,537	18,686	18,926	19,253	0.8%	1.3%	1.7%

1/ calculated from un-rounded numbers

2/ revised classification

3/ by North American Industry Classification System (NAICS) grouping

4/ current Schedules 32S & 83S

5/ current Schedule 83P

6/ current Schedules 83T & (old) Schedule 99

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts

History and Forecast

	2003	2004	2005	2006
Building Permits [1]				
Single-Family	18,232	21,173	23,434	21,385
Multiple-Family	6,495	6,926	7,147	7,114
New Connects				
Single-Family	6,763	6,859	7,787	8,752
Multiple-Family	4,890	4,424	4,585	4,770
Manufactured Home	289	262	267	300
Other	228	244	197	240
Total Connects	12,170	11,789	12,837	14,062
Vacancy Rates (%)				
Single-Family	3.9%	4.1%	4.1%	4.2%
Multiple-Family	11.7%	11.8%	10.8%	10.2%
Mobile Home	9.5%	9.8%	9.6%	9.5%
Number of Occupied Accounts				
Single-Family Heat	103,191	103,421	104,042	104,596
Single-Family Non-Heat	299,802	304,682	310,607	316,705
Multiple-Family Heat	142,936	144,283	147,381	149,786
Multiple-Family Non-Heat	32,685	34,966	38,163	41,241
Mobile Home Heat	28,533	28,426	28,503	28,523
Mobile Home Non-Heat	3,608	3,606	3,626	3,627
Other	4,232	4,609	4,918	5,106
Total Occupied Accounts	614,988	623,994	637,241	649,585
Total Number of Customers [2]	658,232	668,830	680,610	693,088

1/ Oregon

2/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at normal weather)

	2003[1]	2004[1]	2005	2006
Use Per Occupied Account (kWh)				
Single-Family Heat	17,063	17,366	17,038	17,212
Single-Family Non-Heat	10,872	11,119	11,076	11,086
Multiple-Family Heat	9,957	10,098	9,857	9,931
Multiple-Family Non-Heat	6,213	6,471	6,431	6,458
Mobile Home Heat	16,342	16,759	16,433	16,521
Mobile Home Non-Heat	11,283	11,718	11,612	11,693
Other	10,042	10,344	9,912	9,393
Average Use per Occupied Account	11,701	11,913	11,723	11,741
Ultimate Deliveries (millions of kWh)				
Single-Family Heat	1,761	1,796	1,773	1,800
Single-Family Non-Heat	3,259	3,388	3,440	3,511
Multiple-Family Heat	1,423	1,457	1,453	1,488
Multiple-Family Non-Heat	203	226	245	266
Mobile Home Heat	466	476	468	471
Mobile Home Non-Heat	41	42	42	42
Other	42	48	49	48
Schedule 7	7,196	7,433	7,470	7,627
Residential Lighting et al.	5	7	7	7
Total Residential Deliveries	7,201	7,440	7,477	7,633

1/ weather adjusted actual

Commercial Deliveries Forecast by NAICS Cluster

(at normal weather)

	(in million kWh)				% Change [1]		
	2003 [2]	2004 [2]	2005	2006	2004	2005	2006
Food Stores	478	496	498	516	3.7%	0.4%	3.5%
Govt. & Education	917	954	957	957	4.0%	0.3%	(0.1%)
Health Services	571	604	606	665	5.8%	0.3%	9.7%
Lodging	123	119	110	115	(3.4%)	(7.8%)	4.6%
Misc. Commercial	620	665	717	725	7.3%	7.8%	1.1%
Merchandise Stores/Malls	355	350	367	373	(1.4%)	5.0%	1.7%
Office & F.I.R.E [3]	887	940	956	983	6.0%	1.7%	2.8%
Other Services	814	786	790	816	(3.4%)	0.5%	3.2%
Other Trade	799	794	804	831	(0.6%)	1.2%	3.4%
Restaurants	440	438	444	457	(0.5%)	1.5%	2.9%
Trans., Comm. & Utility	575	614	615	627	6.7%	0.2%	1.9%
Total Commercial	6,580	6,761	6,866	7,064	2.7%	1.5%	2.9%

1/ calculated from un-rounded numbers
2/ weather-adjusted actual
3/ Finance, Insurance and Real Estate

Manufacturing Deliveries Forecast by NAICS Cluster

(at normal weather)

	(in million kWh)				% Change [1]		
	2003	2004	2005	2006	2004	2005	2006
Food & Kindred Products	246	232	232	238	(5.8%)	(0.0%)	2.5%
High Tech	1,523	1,524	1,568	1,653	0.0%	2.9%	5.4%
Lumber & Wood	156	169	151	153	8.4%	(10.6%)	1.3%
Primary & Fab. Metals	579	496	517	542	(14.3%)	4.1%	4.9%
Other Manufacturing	539	599	594	611	11.0%	(0.8%)	3.0%
Paper & Allied Products	1,315	1,071	1,115	947	(18.6%)	4.1%	(5.1%)
Transportation Equipment	194	196	199	203	0.8%	1.8%	2.1%
Total Manufacturing	4,553	4,286	4,376	4,348	(5.9%)	2.1%	(0.6%)

1/ calculated from un-rounded numbers

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

	(in million kWh)				% Change		
	2003	2004	2005	2006	2004	2005	2006
Secondary (Residential)							
Outdoor Area Lighting [1]	5.4	6.9	6.9	6.8	26.8%	(0.0%)	(1.2%)
Secondary (General Service)							
Outdoor Area Lighting [2]	18.4	16.7	16.7	16.7	(9.1%)	0.2%	(0.5%)
Farm Irrigation et al. [3]	80.3	79.3	87.1	87.5	(1.2%)	9.9%	0.4%
Service to Drainage [4]	1.8	0.7	0.7	1.3	(61.5%)	(4.0%)	89.1%
Street and Other Lighting [5]	101.4	101.7	102.2	102.7	0.3%	4.2%	0.5%
Total Misc. Commercial	201.9	198.5	206.8	208.2	(1.7%)	0.7%	0.7%
All Misc. Schedules	207.4	205.4	213.7	215.0	(1.0%)	4.1%	0.6%

1/ Existing Schedule 14R

2/ Existing Schedules 14C & 15C

3/ Existing Schedules 47 & 49

4/ Existing Schedule 97

5/ Existing Schedules 91, 92 & 93

Forecast of 2006 PGE Net and Opt-Out Loads

(at normal weather)

(in million kWh)

	PGE Net [1]	Opt-Out [1]	Total [1]
Total Residential	7,633	0	7,633
Secondary Voltage	7,440	198	7,638
Primary Voltage Service	2,417	330	2,747
Transmission Voltage Service	658	474	1,132
Street Lights	103	0	103
Total Deliveries	18,252	1,001	19,253
Average MW [2]	2,241	119	2,361
Peak MW [3]	3,602	148	3,721

1/ cycle basis for PGE Net or "Cost of Service", Opt-out or "Non-Cost of Service" and Total Deliveries; totals do not add up due to rounding

2/ calendar basis

3/ co-incidental with winter system peak; "Opt-out" co-incidental peak of 148 MW is in June

CERTIFICATE OF SERVICE

I certify that I have caused to be served the **REBUTTAL TESTIMONY AND WORKPAPERS OF PORTLAND GENERAL ELECTRIC COMPANY** in OPUC Docket No. UE 172, by U.S. Mail and electronic mail, to the following parties from the official service list maintained by the Commission:

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DATED this 19th day of August, 2005.

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