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I. Introduction

1 **Q. Please state your name and position with PGE.**

2 A. My name is Maria M. Pope. I am the Senior Vice President, Finance, Chief Financial
3 Officer and Treasurer for PGE. My qualifications appear at the end of this testimony.

4 **Q. What is the purpose of your testimony?**

5 A. The purpose of my testimony is to discuss PGE's efficiency and cost effectiveness efforts. I
6 also propose changes to PGE's power cost adjustment mechanism. With regard to the
7 efficiency and cost effectiveness portion, my purpose is to:

- 8 • Discuss and provide examples of PGE's ongoing commitment to efficiency and cost
9 effectiveness and future plans to improve; and
- 10 • Compare our operational costs with other utilities.

11 **Q. Why are you providing this efficiency and cost effectiveness testimony now?**

12 A. We are providing this testimony now for several reasons. First, we believe parties expect
13 PGE to describe its efforts to gauge and improve efficiency and cost effectiveness. Second,
14 we realize that we need to do a better job documenting and communicating to our
15 customers, regulators, and the public the many cost efficient and innovative operational
16 improvements PGE is undertaking. Finally, the external environment is changing, which
17 requires that we intensify our efforts to respond to new environmental, economic,
18 technological and other external changes. The changing environment presents an
19 opportunity to examine the requirements of our work and our performance.

20 **Q. Please explain what you mean by efficiency.**

21 A. Efficiency is aimed at how we deliver reliable energy and service to customers while
22 maintaining standards for safety and regulatory compliance. Technically, efficiency is
23 measured by comparing the ratios of output to input. A system increases its cost efficiency

1 when it maintains output with fewer or less costly input(s), or conversely delivers higher
2 value to customers for the same or lower cost. Our efficiency and cost effectiveness efforts
3 aim to contain or reduce costs while keeping our high quality of customer service and
4 system reliability. We are not effective if our system is not safe, not reliable, or we are not
5 providing good customer service. This differs from mere cost cutting; obtaining the lowest
6 absolute cost is not a responsible goal if it sacrifices our effectiveness in delivering safe,
7 reliable power.

8 **Q. Why is efficiency and cost effectiveness important?**

9 A. Efficiency and cost effectiveness are an important part of our culture at PGE. Efficiency
10 and cost effectiveness means our customers are getting more for their money. Customers
11 expect us to do whatever we can to keep costs down while delivering safe, reliable power
12 and good customer service. This is especially important as our customers are beset by the
13 recessionary economy. For employees, working for an efficient organization is a source of
14 pride.

II. Establishing a Culture of Efficiency and Cost Effectiveness

1 **Q. You stated the external business environment is changing, how are you responding?**

2 A. We are embarking on a new phase of efficiency and cost effectiveness. Historically, many
3 business units within PGE have implemented efficiency and cost improvements, often in
4 partnership with another business unit with which they share a common process. Our
5 renewed commitment to efficiency and cost effectiveness starts with a more centralized
6 corporate focus and organization to drive improvements at an overall corporate level, setting
7 standards and expectations, providing resources, sharing examples, and monitoring and
8 reporting on improvements. The approach of reinforcing a culture of improvement and
9 efficiency is distinct from mere budget cuts. We have implemented budget cuts as a
10 short-term, temporary solution to a changing economic environment, but these cuts do not
11 reflect efficiency gains. See PGE Exhibit 100. Budget cuts of this type do not reengineer
12 business processes by design and may create inefficiency if there is no change to underlying
13 processes.

14 **Q. Please describe the new phase to enhance PGE's culture of efficiency and cost**
15 **effectiveness.**

16 A. The new phase is being led by a team with corporate-wide focus, the Corporate Performance
17 Management group,¹ the manager of which reports directly to me. The corporate-wide
18 efficiency charge builds on the proven track record of this group's previous work with the
19 Customer Service and Delivery organization. The group is responsible for working with
20 functional areas across PGE, assisting them with establishing meaningful performance
21 measures, benchmarks, best practice applications, and providing project management and

¹ The Corporate Performance group was assembled from existing employees from Customer Service and Delivery. See PGE Exhibit 1000, Corporate Support, Table 1.

1 process improvement services. The group is also charged with assisting management in
2 refining performance measurement and targets. The group has set up a Sharepoint intranet
3 site, entitled “Company Improvements,” to share efficiency and benchmarking examples
4 company-wide. The site enables all employees to post their own efficiency and cost
5 effectiveness, and benchmarking examples and to read others. This approach creates an
6 informal network for managers to learn from each other, encourage employees to suggest
7 improvements, and drive improvement throughout PGE.

8 The Corporate Performance Management group is also working to develop an
9 enterprise-wide benchmarking strategy and will identify industry best practices to further
10 our continuous improvement culture. The goal is to benchmark key performance metrics in
11 conjunction with any new system implementation to establish a baseline and inform the
12 design of the new system. Benchmarking is the first step; the value creation is in the
13 improvement work that follows.

14 **Q. How is this different from what you have been doing?**

15 A. We are instituting a renewed corporate focus to lead, coordinate, and facilitate efficiency
16 improvements throughout the company. In the past, efficiency efforts were primarily
17 undertaken at the business unit level and not necessarily shared or coordinated company-
18 wide. Some managers had the skills and resources to drive cost efficiencies and process
19 improvements, while others did not.

A. Initial Measurement of PGE's Costs Relative to Others

1 **Q. Has PGE evaluated its costs relative to others?**

2 A. Yes. PGE has performed cost comparisons by comparing PGE's FERC Form 1 costs with
3 the Western Electricity Coordinating Council (WECC)² and NW Utilities³ annually. The
4 FERC Form 1 analyses compare the cost of performing sets of activities related to the
5 standard utility functions with other utilities and industry groups on a per customer or per
6 kWh basis. In addition, we recently retained the Pacific Economics Group (PEG), which
7 uses an econometric modeling approach that goes a step further by identifying utility O&M
8 cost drivers.

9 **Q. What is the difference between cost comparisons and benchmarking?**

10 A. We make a distinction between cost comparisons and benchmarking. The cost comparisons
11 stop at the comparison and do little to explain the factors causing discrepancies and identify
12 areas for improvement. Also, cost comparisons do not help identify best practices to inform
13 improvement.

14 In contrast to the cost comparison snapshot approach, benchmarking takes the process
15 further to identify reasons, including operational strengths and areas for improvement, for a
16 given performance, and help identify best practices. Once the performance baseline is
17 known, managers can target areas for improvement, establish better metrics, implement
18 changes, and measure and monitor the effects of changes on performance. Benchmarking is
19 an ongoing process, not an event.

² The WECC utilities include: Arizona Public Service Company, Avista Corporation, Black Hills Power, Inc., El Paso Electric Company, Idaho Power Co., Nevada Power Company, NorthWestern Energy Division, Pacific Gas and Electric Company, PacifiCorp, Public Service Company of Colorado, Public Service Company of New Mexico, Puget Sound Energy, Inc., San Diego Gas & Electric Co., Sierra Pacific Power Company, Southern California Edison Co., Tucson Electric Power Company, and PGE.

³ The NW utilities include: Avista Corporation, Idaho Power, NorthWestern Energy Division, PacifiCorp, and Puget Sound Energy, Inc.

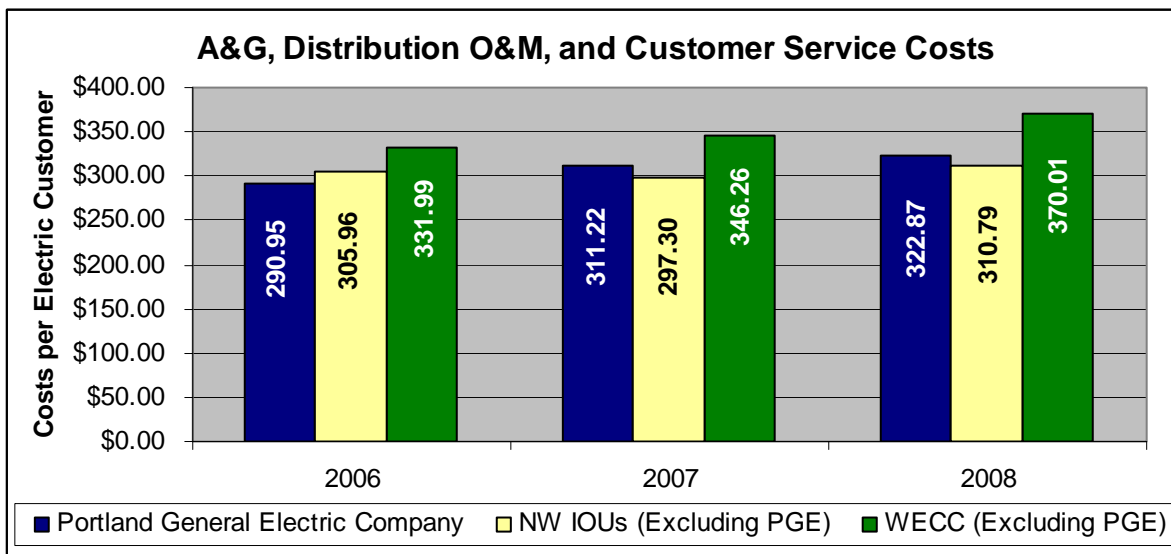
1 **Q. Explain further what you mean by comparing utility functions.**

2 A. The FERC Form 1 and PEG comparisons focus on costs for PGE to perform activities
 3 related to a particular high level function, (e.g. Distribution O&M), against another utility or
 4 industry group. In both the PGE internal and PEG analyses, information from FERC Form 1
 5 data is used. These approaches provide snapshots of PGE’s costs relative to a group of peers.

6 **Q. What did you learn from the FERC Form 1 comparisons?**

7 A. Figure 1 below provides a cost comparison of aggregated Administrative and General
 8 (A&G), Distribution O&M, Customer Accounts and Service (Customer Service Costs) on a
 9 per customer basis for PGE, NW Utilities, and WECC utilities for 2006-2008. These
 10 represent our major O&M cost components except for Generation O&M and Transmission
 11 O&M.⁴

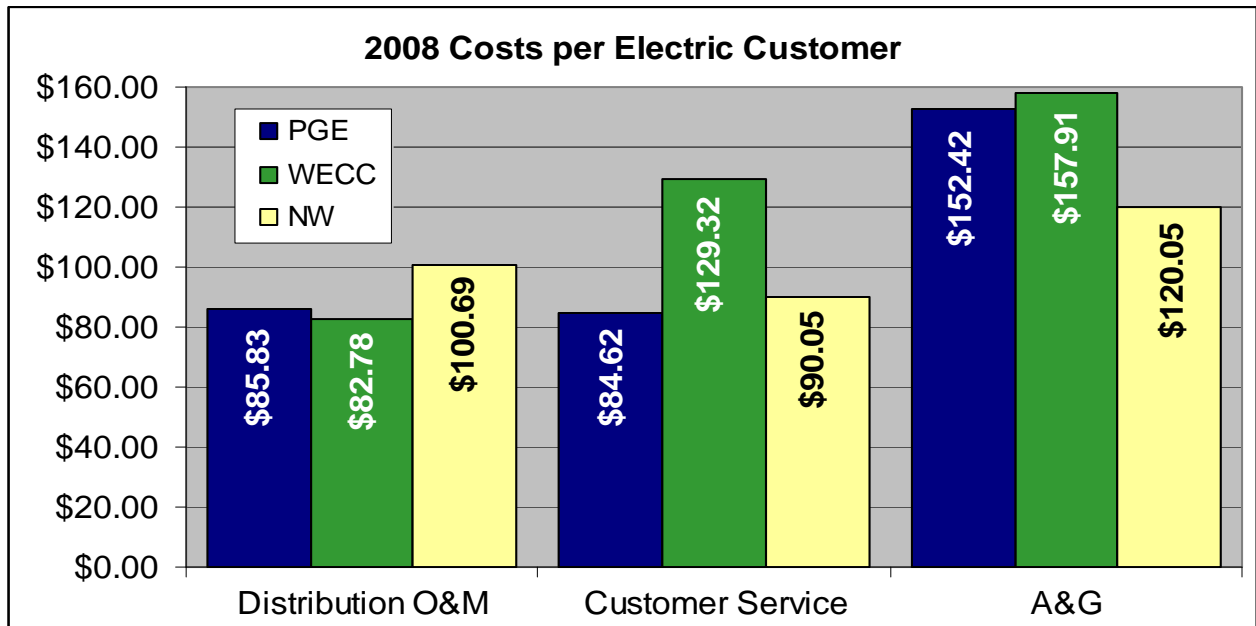
Figure 1



12 Figure 2 provides a snapshot of the most recent data (2008) and breaks out the
 13 functional areas compared.

⁴ We have excluded Transmission because we have fewer transmission investments than other utilities in our region. In addition, we excluded Generation O&M because it is highly dependent on the particular generation fleet of a utility, making comparisons very difficult.

Figure 2



1 **Q. What are the limitations of the FERC Form 1 comparisons?**

2 A. The FERC Form 1 analysis, while one indicator, has some shortcomings and does not tell
 3 the full story of effectiveness and cost. The FERC Form 1 analysis does not measure the
 4 quality of the outputs such as customer service, safety and reliability. In addition, utilities
 5 do not account for all costs in the same way. Overhead costs may be allocated to functional
 6 areas by some and not by other utilities. Each utility has its own set of unique circumstances
 7 based on its particular physical, economic, and regulatory environment. For example, some
 8 utilities conduct their own energy efficiency programs and their costs of doing so are
 9 included. In Oregon, programs are conducted by the Energy Trust of Oregon (ETO).
 10 Another example of noncomparability is in tree trimming costs which, in wet climates are
 11 usually higher than for utilities in more arid regions.

12 **Q. If this is the case, are these studies relevant?**

13 A. FERC Form 1 comparisons provide an indication of what categories of costs may deserve
 14 additional analyses and evaluation. Disparate trends may indicate further research is

1 needed. To delve deeper into comparing our O&M costs with others, we retained PEG to
2 apply their econometric modeling approach and compare our total O&M costs.

3 **Q. Who is the PEG and what is their expertise?**

4 A. PEG is a research group that specializes in statistical cost research for the energy utility
5 industry. A number of entities including utilities, regulators, and industry groups, have
6 retained PEG to testify, prepare papers, and teach performance benchmarking. Among their
7 client list are: the Louisiana and Michigan Public Service Commissions, Edison Electric
8 Institute, Electric Utility Consultants, Inc. (EUCI), Wisconsin Public Utility Institute,
9 Michigan State University Public Utilities Institute, Center for Regulatory Studies,
10 Oklahoma Gas and Electric, Hawaiian Electric, Central Vermont Public Service, Canadian
11 Electricity Association, Ontario Energy Board, and other international clients.

12 **Q. Describe the approach taken by the PEG and how it is useful in measuring utility
13 performance.**

14 A. PEG's approach uses an econometric model that goes a step further than the FERC Form 1
15 functional cost comparisons. The econometric model was based on a sample of data for 105
16 U.S. power distribution and 54 power generation companies.

17 In developing its model, PEG attempts to identify the overall drivers of a utility's costs
18 for all the utilities in the sample. The model is equipped to take into account, for example
19 with distribution O&M, labor prices, material and service cost, and also business condition
20 variables that affect the cost of providing distribution services like the extent of a system's
21 overhead lines. The extent of overhead facilities affects distribution O&M costs because
22 lines are more exposed to weather challenges and trees. Please see PEG report for more
23 information on variables and the econometric modeling approach, included as PGE Exhibit
24 201.

1 The model compares PGE’s costs from FERC Form 1 and also includes the business
2 condition variables to predict a cost benchmark where PGE’s costs should be relative to the
3 peer group. A negative score and high confidence level means that PGE is better than the
4 peer group in that functional cost category. A positive score and high confidence level
5 means that PGE is worse than the peer group in that functional cost category.

6 **Q. Did PEG perform benchmarking?**

7 A. Not in the full sense of the concept as explained earlier. While often referred to as
8 “statistical benchmarking,” we see it as a more sophisticated cost comparison approach that
9 provides us more information on cost drivers when we compare our performance to others.
10 It did not attempt to explain the difference between PGE’s performance and other utilities. It
11 does, however, give us key cost driver data to examine as we delve deeper into reasons
12 behind our standings.

13 **Q. Which components of PGE’s operations did PEG address in its comparisons?**

14 A. We asked them to focus on three areas concerning efficiency and cost effectiveness:

- 15 • 1) O&M expenses in Distribution, Customer Accounts and Service, and A&G
- 16 (DCA) on an aggregated basis;
- 17 • 2) Non-fuel Generation O&M; and
- 18 • 3) Reliability using the System Average Interruption Duration (SAIDI)⁵ and
- 19 System Average Interruption Frequency Indices (SAIFI).⁶

⁵ SAIDI is the total time, in a year, without power for the average customer, measured in minutes. It is an indicator of system reliability. All planned and unplanned interruptions of five minutes or more are included in the calculation. Major events are excluded. PGE’s goal is fewer than 90 minutes.

⁶ SAIFI is the frequency, or how often the average customer loses power, measured in times per year. All outages affecting one customer or more, lasting five minutes or more, are counted. Major events are excluded. PGE’s goal is fewer than 1.2 times.

1 We did not include Transmission O&M because of our small investment in this part of the
2 business.

3 **Q. What are the key empirical results of the econometric modeling?**

4 A. The results were as follows:

- 5 • DCA: PGE's DCA costs are approximately 11% below the model's prediction on
6 average from 2006-2008. However, at the 90% confidence level, PGE's costs are
7 not statistically different from the average over the period.
- 8 • Generation: PGE's generation O&M yielded a similar result, and was found to be
9 5% below the econometric cost model's prediction on average from 2006-2008.
10 At the 90% confidence level, PGE's generation costs are not statistically different
11 from average costs over the period.
- 12 • Reliability: With regard to SAIDI and SAIFI, the results of the statistical
13 benchmarking mean that PGE's reliability performance is "significantly
14 superior," with both the SAIDI and SAIFI results far below the cost benchmarks
15 on average from 2006-2008, at 67% and 48% respectively. To ensure that similar
16 outage and frequency measures are used to compare reliability performance, PEG
17 used only the SAIDI and SAIFI indices, which are based on the Institute of the
18 Electrical and Electronics Engineers (IEEE) standards. While Oregon holds PGE
19 to a higher standard than the IEEE standard, we provided the IEEE based SAIDI
20 and SAFI data to PEG so "apples to apples" comparisons could be made. Please
21 see PGE Exhibit 800 for discussion of PGE's Reliability Service Quality
22 Measure.

23 **Q. What conclusion do you draw from the results?**

1 A. Similar to the FERC Form 1 results, the PEG results show that we match up well with the
2 industry on DCA and generation and are performing in the superior category for reliability,
3 while keeping our reliability related costs in line with the industry.

4 • DCA: PGE's aggregated O&M costs are in line with industry standards, with
5 which we match up well in terms of average O&M costs. Despite matching up
6 well on O&M costs, we are still driven to improve our efficiency and cost
7 effectiveness. Business conditions and requirements are always changing which
8 requires ongoing review of the work (how it is done, the costs, and the
9 effectiveness). We are not satisfied with being in line with the industry. We want
10 to continuously improve.

11 • Generation: PGE is in line with the industry according to the PEG analysis. We
12 note that while the model for non-fuel Generation O&M takes into account
13 several generation cost drivers, O&M costs vary significantly with the type and
14 age of plants owned by a participating utility. In addition, it is difficult for a
15 model such as PEG's to capture the impact of significant unique attributes that
16 may influence generation O&M, such as the relatively low capacity factors for
17 thermal plants in the Northwest due to the impact of spring hydro runoff. While
18 we include the results for completeness, we do not believe that the Generation
19 results are as meaningful as the analysis of Distribution, Customer Accounts and
20 Service, and A&G.

21 • Reliability: PEG terms our reliability results "significantly superior." Our SAIDI
22 and SAIFI performance indicates that we are achieving a very high level of
23 reliability at industry average cost levels. We have focused on system reliability
24 because we know it is important to customers. Customer satisfaction with

1 reliability is evidenced in recent residential, industrial and general business
2 customer satisfaction surveys. The 2009 JD Power Residential customer surveys
3 indicate a high level of satisfaction with PGE's power quality and reliability,
4 placing PGE in the top quartile of performance, or "elite" category, for utilities
5 across the country.⁷ PGE's largest industrial customers also give PGE high marks
6 for reliability. In the 2009 TQS Research, Inc. study of the largest energy users
7 (over 1000 kw), PGE ranks 11th out of 58 utility holding companies nationally on
8 industrial customer satisfaction with reliability, with 86.6% of respondents very
9 satisfied⁸ and another 11.9% somewhat satisfied. In the same survey, PGE ranked
10 10th out of 58 on minimum outages.⁹ Similarly, our general business customers
11 give PGE high marks for reliability and customer service. In the 2010 JD Power
12 survey, general business customers ranked PGE's power quality and reliability
13 first in the region and seventh nationally out of 82 utilities. We are achieving
14 high reliability marks according to our customers and compared with other
15 utilities, and we are in line with average industry costs.

16 **Q. What are your next steps for further cost analysis and improvement?**

17 A. The next steps are being led by our Corporate Performance Management group, discussed
18 earlier. The group is working with officers and managers to set forth an organizational

⁷ The JD Power ranking for reliability relates to the following components: supplying electricity during very hot and very cold temperatures, avoiding power interruptions of five minutes or less, avoiding outages of more than five minutes, keeping customers informed of an outage, promptly restoring power after an outage, and providing quality power without spikes, drops or surges.

⁸ The components of overall reliability in the TQS Survey include: keeping unplanned outages to a minimum, keeping outages lasting less than a minute to a minimum, coordinating planned outages with customers, timely restoration of power, being easy to contact and get information during an outage, and number of times the customer lost power due to unplanned outages.

⁹ Other results in the TQS survey related to reliability include the following PGE rankings: 4th out of 58 on how well PGE coordinates outages with the industrial customer's operations; 10th out of 58 on restoration; 3rd out of 58 on ease with which the customer can reach PGE during an outage; 4th out of 58 on outage information, and 10th out of 58 on satisfaction with overall power quality.

1 benchmarking plan over a multiple year cycle. The plan will focus on areas of PGE that are
2 key performance contributors. Over a cycle of four to five years, nearly every area of PGE
3 will have an opportunity to participate in a targeted benchmarking study. We will also
4 benchmark areas selected for large system upgrades as a way to improve the system design.
5 The goal is a cycle of benchmarking and continuous improvement, reinforcing our corporate
6 culture of efficiency and cost effectiveness.

7 **Q. What strategic benchmarking is PGE planning?**

8 A. In 2010, our strategic benchmarking is focused on the replacement of the finance and
9 accounting system, the first system to be replaced as part of PGE's 2020 Information
10 Technology Initiative, also known as "2020 Vision." Please see PGE Exhibit 600, Section
11 IV, Part B, for more information on this initiative. Prior to replacement, PGE is
12 benchmarking key processes and functions to identify performance metrics, determine best
13 practices, and have the best practices inform the design of the finance and accounting
14 system. Once the finance and accounting system is designed, constructed, and implemented,
15 PGE's costs and performance will be reviewed against best industry practices, helping
16 managers identify areas for process improvements.

17 **Q. Has PGE performed any other benchmarking?**

18 A. Yes. In an internal 2009 survey, twenty-two PGE business units reported they are either
19 currently participating or have recently participated in "benchmarking" studies. Many of
20 these may be comparison and not benchmarking studies. These units include: sourcing and
21 contracts, fleet and transportation services, safety and health, internal audit, customer
22 satisfaction, and compensation and benefits. Many of the reported "benchmark" studies are
23 directed at outputs like customer satisfaction, customer ease of navigation on PGE's
24 Web site, market compensation data, and employee accident rates. Sometimes the studies

1 were undertaken to identify PGE's performance or costs and to trend these relative to others,
2 and other studies identified best practices, (e.g., customer satisfaction studies and ease of
3 access to web studies). We expect comparison and benchmarking studies at the business
4 unit level to continue. An inventory of survey responses is attached as PGE Exhibit 202.

B. Examples of System Efficiencies

5 Q. Does PGE have any large scale projects leading to efficiencies?

6 A. Yes. Recent large scale projects include:

- 7 • Automated Metering Infrastructure (AMI): The current project to replace all of
8 our electric meters with smart meters will yield significant annual operating
9 benefits, approximated at \$16.5 million for 2011. We estimate approximate
10 capital cost of about \$132 million for this project. Future operating benefits could
11 be higher. In addition to these benefits, it also lays the foundation for customer
12 and system benefits from additional programs that will take advantage of the
13 technological platform and new information the AMI system provides. For a list
14 of the customer and system benefits envisioned, please see PGE Exhibit 300,
15 Section III, Part C. AMI is an example of increasing both the efficiency and
16 effectiveness of the system.
- 17 • Boardman Upgrades: In 2000 and 2004, PGE replaced the low pressure and high
18 pressure/intermediate pressure turbines at Boardman at a cost of \$16.8 million.
19 PGE chose to upgrade the turbines to enable the plant to capture more energy
20 from the same amount of fuel and further increase output. After the turbines were
21 installed, electricity output at Boardman increased by about 35 MW from the
22 2000 upgrade and 32 MW from the 2004 upgrade for the same fuel input. (PGE's
23 share was 22.75 MW and 20.8 MW, respectively). The increased energy output

1 of both upgrades represented an improvement of approximately 12% in efficiency
2 and output. At today's power market prices and based on PGE's 65 percent share
3 of the plant's power output, this is a savings of \$15.6 million annually.¹⁰

- 4 • Coyote Springs Upgrade: Included in this filing, (see PGE Exhibit 700), is a
5 project to upgrade Coyote Springs. The upgrade will result in approximately 15
6 MW additional capacity and an improved plant heat rate, thus reducing power
7 costs. The upgrades will reduce inspection requirements and extend the life of the
8 rotors for more reliable operation. A new control system permits a larger plant
9 operating range and more dispatch flexibility which can aid in the integration of
10 wind resources into the PGE system.

- 11 • Taxes:

- 12 ○ Sherman County Property Tax Savings: The decision to site Biglow Canyon
13 Wind Farm in Sherman County produced a savings of \$30-\$40 million in
14 property taxes over 15 years, starting in 2008, through Sherman County's
15 Strategic Investment Initiative. For further discussion, please see PGE Exhibit
16 300.

- 17 ○ Columbia County Property Tax Savings: The decisions to locate Port
18 Westward in a Columbia County enterprise zone and hire local county
19 residents produced an additional \$12 million in property tax savings over five
20 years. For further discussion, please see PGE Exhibit 300.

- 21 • Virtual Computer Network Servers: Physical servers have been consolidated to
22 reduce the initial hardware costs and the operating costs of physical servers.

¹⁰ The approximated savings is calculated using an 80% operation of Boardman (100% is 8,760 hours per year). The 80% is approximated from 46 days of maintenance scheduled in 2011 and a 10% forced outage. The flat average forward cost of power used is \$51 /MWh and PGE owns 65 percent of the plant and output.

1 Virtual servers reduce data center power and cooling costs in addition to reduction
2 in overall cost per server. The consolidation to virtual servers has reduced the
3 need for 201 additional Windows physical servers down to eight physical hosts.
4 The result is a net capital cost savings of approximately \$1.2 million. Please see
5 PGE Exhibit 600 for more information.

C. Efficiency and Cost Effectiveness in Operations

6 **Q. Did PGE also implement changes in the operational day-to-day activities that led to**
7 **cost efficiencies?**

8 A. Yes. We have several operational methods that reinforce efficiency and cost effectiveness
9 in our daily operations including: budget development and management, goods and services
10 procurement, and power purchases and sales.

11 **Q. In addition to these operational methods has PGE implemented any actions leading to**
12 **specific operational cost efficiencies?**

13 A. Yes. We have implemented smaller operational efficiencies throughout PGE. The
14 operational efficiencies are geared toward doing our day-to-day work, improving and
15 redesigning business processes, which includes streamlining, eliminating duplication and
16 unnecessary steps, and using technology. Refer to PGE Exhibit 203 for examples.

17 **Q. How does PGE reinforce efficiency and cost effectiveness through its budget process?**

18 A. The goal of the budget process is to best allocate limited resources to achieve our corporate
19 goals of delivering safe, reliable power and efficient customer service. PGE does this in a
20 continuously changing environment with regard to regulation, the economy, technology, and
21 customer expectations. These all impact how we do our work and the associated costs. As
22 costs increase, we focus on doing our work efficiently to mitigate the effect of cost increases
23 on our customers.

1 **Q. How do O&M budgets reflect a commitment to efficiency and cost effectiveness?**

2 A. Our O&M budget process relies on managers to know their areas of responsibility, including
3 how the work is accomplished and the resources required to perform it. With officer
4 guidance, managers develop budgets and must identify variances from the previous year's
5 budget. Proposed budgets are then reviewed by senior managers and officers and
6 adjustments are made as appropriate. Officers review actual results compared to budget on
7 an income statement line-item basis. To the extent that variances are significant, the CEO
8 may direct officers to find offsetting reductions. On a regular basis, analysts and managers
9 monitor actual expenses and revenues, taking corrective action in response to deviations.
10 The budget reports and management and executive review serve as controls during the
11 budget year. Absent justifiable and unforeseen circumstances, spending is within budgeted
12 limits.

13 **Q. How do capital budgets reflect a commitment to efficiency and cost effectiveness?**

14 A. The Capital Review Group, a cross functional group of senior PGE managers, reviews all
15 proposed capital projects (except major construction projects such as Biglow Canyon and
16 AMI). Projects are prioritized and the group recommends to the CEO which ones should
17 proceed. Project approval ensures that plans to commit resources receive thorough scrutiny,
18 appropriate authorization, and adequate follow-up. If the project scope changes significantly
19 after it has been approved, the project is again reviewed.

20 **Q. How does PGE reinforce efficiency and cost effectiveness through procurement**
21 **processes?**

22 A. PGE's general procurement strategy uses a competitive process led by the Sourcing and
23 Contracts team of specialized buyers. The buyers are familiar with vendors, products, and

1 services as well as the current market conditions. With regard to commonly used items like
2 cable and transformers, PGE negotiates volume pricing and discounts.

3 For significant purchases, we promote formal bidding. Construction projects, for which
4 there is a defined scope of work and available contractors, are nearly always bid, although
5 the type of the contract may differ. Bids are evaluated based on total ownership cost¹¹ and
6 awarded to the lowest evaluated bidder. However, cost of the good or service, while
7 important, is not the only factor. For example, fleet purchases, (e.g., hybrid or specialized
8 equipment) may have other factors such as the uniqueness of the required product. In
9 software purchases, factors like maintenance or change-out costs may significantly influence
10 the purchasing strategy. In these cases, users are required to justify single or sole sources
11 for the purchase. In many areas, procurement decisions are a collaborative effort with the
12 department that uses the good or service.

13 **Q. How does PGE reinforce efficiency and cost effectiveness in power purchases and**
14 **sales?**

15 A. As an energy deficient utility, PGE's key strategy in power purchases and sales is to 1)
16 assure that PGE meets current and forecasted customer energy needs short-term and
17 long-term at the best power cost, and 2) reduce price volatility for customers. The Power
18 Supply group does this in a number of ways through its use of brokers, energy market
19 counterparties and participation in industry groups.

20 The Power Supply group employs a time-diversification strategy for energy purchases
21 and sales, meaning that PGE generally layers the purchases and sales over the course of
22 multiple weeks, months, and even years. This strategy is used to help PGE take advantage

¹¹ Total ownership cost is a comprehensive systems approach to analyzing purchases, processes, and supply chain-related decisions.

1 of pricing opportunities for market purchases, and also as a means to reduce customer rate
2 volatility. To achieve the best possible transaction value for this strategy, PGE uses multiple
3 brokerage firms, which are paid a fee only if a transaction is completed. Over-the-counter
4 (OTC) power brokers match power buyers and sellers, much like a real estate broker
5 matches home buyers and sellers.

6 In contrast to exchange-based clearing brokers, OTC brokers do not act as
7 counterparties, do not take title to power, and do not make financial or physical
8 commitments to provide power. The OTC brokers can be electronic, like the Inter-
9 Continental Exchange (ICE) which is akin to E-Trade, or "voice brokers." Voice brokers
10 use people to perform their brokering services over dedicated phone lines and "squawk
11 boxes" that reach their customers. In either case, the OTC brokers have the infrastructure in
12 place to reach many power trading counterparties at one time, and by utilizing several
13 brokerage firms at once, PGE greatly expands its market coverage in a manner that would
14 otherwise be impossible for PGE to achieve without significant additional staffing.

15 In markets for "non-standard products," PGE also has direct transactions with energy
16 market counterparties. Non-standard products refer to volumes, terms, and energy shapes
17 that do not fit neatly into the highly commoditized standard on-peak and off-peak fixed price
18 categories handled by brokers. These direct contacts allow PGE to acquire products that
19 better fit customer needs. These products include, but are not limited to, energy exchanges,
20 capacity purchases, merchant transmission and transport management.

21 Lastly, PGE works diligently in regional regulatory, reliability, and wholesale energy
22 customer forums in an attempt to positively influence policies that impact PGE customers.

23 PGE has been very active in Mid-Columbia Operating and Technical Committees for hydro
24 concerns, with WECC, Western System Power Pool, and the Pacific Northwest Utilities

1 Conference Committee for topics of reliability, reserves, and wind integration costs, and
2 directly with BPA Transmission to ensure that energy from PGE resources can be wheeled
3 back to PGE's service territory in a cost-effective manner.

4 **Q. Do you have examples of changes in operations that led to efficiencies?**

5 A. Yes. I have included a number of examples in PGE Exhibit 203.

6 **Q. Have you heard concerns about PGE's efficiency and cost effectiveness from**
7 **investors?**

8 A. Not really. Investors expect us to be efficient and cost effective. Investors, analysts and
9 rating agencies are continuously comparing PGE with other utilities based on broad sets of
10 data and they do not see us as an outlier on our O&M costs. They do see us as an outlier in
11 terms of issues like our power cost adjustment mechanism, and the impact of hydro
12 conditions on power costs,¹² which make it more difficult to predict PGE's cost recovery,
13 corporate performance and shareholder return. Our O&M expenses are not the issue for
14 investors because our costs are in line with other utilities.

¹² PGE's AUT filing includes average hydro conditions to forecast Net Variable Power Costs for the following year. This estimate of average is based on 62 years of historical hydro flows. As regional climate conditions change, this calculation no longer represents a true average for hydro flows. Over the past 16 years (1993 - 2009), the region has only experienced either average, or above average, hydro flow conditions, as measured at The Dalles, four years or 25% of the time.

III. Revised PCAM Structure

1 **Q. Please describe PGE's current Power Cost Adjustment Mechanism (PCAM) structure.**

2 A. The current PCAM, approved by the Commission in UE 180¹³ provides for sharing of power
3 cost variances between PGE shareholders and customers based on an asymmetric and
4 dynamic deadband construct, with 90/10 sharing outside of the deadband, and an earnings
5 test with a 100 basis point deadband around the Commission-authorized ROE.

6 **Q. As PGE's Chief Financial Officer, have you heard from investors directly regarding**
7 **the PCAM mechanism?**

8 A. Yes, the comments that I have received both verbally and through analyst reports suggest the
9 investment community views our PCAM negatively as compared to our peers. The negative
10 view is expressed three ways: 1) PGE's PCAM places too much of the power cost variances,
11 including impacts of hydro conditions, on PGE shareholders; 2) It is complicated and
12 difficult to understand and predict how it will affect PGE's power cost recovery; and 3) It is
13 unlike other utility PCAMs and its results are not easily compared with others¹⁴. While this
14 could be justified if PGE received higher authorized ROEs as a result, I do not believe the
15 OPUC has granted such premium ROEs.

16 **Q. Do you have any other support of view that PGE's PCAM is structured**
17 **inappropriately?**

18 A. Yes. We asked Steve Fetter, a former Michigan Commissioner and Chairman, to review
19 PGE's PCAM structure. Mr. Fetter has unique experiences since he has been both a former
20 regulator and has worked in the investment community for Fitch. Mr. Fetter's testimony is
21 provided in PGE Exhibit 1300. I agree with his conclusions that:

¹³ Order 07-015

¹⁴ PGE conducted a study of PCAMs across the country. The study demonstrates that PGE's PCAM structure is an outlier relative to others. This study is included in Work Papers.

- 1) PGE’s PCAM structure does not provide PGE with an adequate opportunity to recover our prudently incurred costs.
- 2) As compared with PCAM structures elsewhere in the country, PGE’s PCAM places an unusually large amount of risk on the company and, as a result, puts PGE at a disadvantage compared to our competitors for capital.
- 3) Our customers will experience higher costs of capital in the long run as a result of our disadvantageous position in capital markets.

Q. What has been PGE’s experience with the current PCAM to date?

- A. Figure 3 below summarizes the results of the PCAM from 2007 through 2009.

Figure 3

	2007	2008	2009
Total Power Cost Variances	\$(29.5) million	\$(31.8) million	\$22.3 million
Customer portion based on Variance Sharing	\$(16.5) million	\$(16.1) million	\$0
Customer portion after Earnings Test application	\$(16.5) million	\$0	\$0
PGE Shareholder portion after Earnings Test application	\$(13.0) million	\$(31.8) million	\$22.3 million

Q. What does this experience demonstrate?

- A. It demonstrates that PGE is subject to significant power cost volatility and a substantial portion of power cost variances remain with PGE shareholders.

Q. How do you propose to revise the PCAM structure?

- A. I propose that the deadband be narrowed, made symmetrical, and be fixed in dollar terms rather than expressed as a function of ROE. In addition, I propose a change to remove the 100 basis point deadband construct in the earnings test. Figure 4 below, summarizes the current and proposed PCAM attributes. A copy of the revised Schedule 126, consistent with this proposal, is included in PGE Exhibit 1501.

Figure 4

Feature	Proposed	Current
Deadband – Higher NVPC	\$10 million	150 bp of authorized ROE. For 2011, this would equate to \$39.9 million.
Deadband – Lower NVPC	\$10 million	75 bp of authorized ROE. For 2011, this would equate to \$(19.95) million.
Earnings Test - Refunds	Refunds will be made such that PGE’s actual regulated ROE is no less than the Commission authorized ROE.	Refunds will be made such that PGE’s actual regulated ROE is no less than 100 bp above the Commission authorized ROE.
Earnings Test – Collections	Collections will be allowed such that PGE’s actual regulated ROE is no higher than the Commission authorized ROE	Collections will be allowed such that PGE’s actual regulated ROE is no higher than 100 bp below the Commission authorized ROE.

1 **Q. Why do you propose these changes?**

2 A. These changes are necessary so that PGE has lower costs of capital over the longer run
3 which translates to lower costs to customers over the longer run. The PGE PCAM structure
4 should be more in line with the structure of mechanisms that apply to our peer utilities. PGE
5 must compete for capital with these peer utilities and a less robust PCAM mechanism
6 coupled with the absence of any compensating increase in the authorized ROE from the
7 Oregon Commission places PGE at a disadvantage in the capital markets. The PCAM
8 structure for our peer utilities and the impact of the PCAM on ROE is discussed further in
9 PGE Exhibit 1200.

10 **Q. How did you determine that \$10 million is an appropriate deadband?**

11 A. The majority of our peers have PCAM structures without any deadband at all, and of those
12 that do, we could find only one with a larger deadband than the equivalent of about 100
13 basis points. However, in recognition that a deadband may provide additional incentives to
14 manage costs, (beyond simple sharing alone), I propose a fixed deadband of \$10 million,
15 that is roughly equal to 40 basis points of ROE on PGE’s expected 2011 rate base.

1 **Q. Why do you propose to modify the earnings test to remove the 100 basis point**
2 **deadband?**

3 A. The earnings test deadband effectively acts as a second deadband above and beyond the
4 power cost variance deadband. A PCAM should not provide for over-earning when power
5 costs are lower and under-earning when costs are higher. The authorized ROE provides a
6 reasonable point for limiting collections/refunds under the mechanism.

7 **Q. Why do you propose to make the deadband symmetrical?**

8 A. An asymmetric deadband is inconsistent with the appropriate goal of a PCAM to allow a
9 utility to collect its prudently incurred cost of service as discussed in PGE Exhibit 1300.
10 The original rationale for this element of the structure was that the risk of power cost
11 variances were asymmetrical (higher power costs being more likely than lower power costs).
12 If this is the case, an asymmetrical deadband ensures that prudently incurred costs will never
13 be collected.

14 **Q. The Commission articulated principles of the PCAM in UE 180 that are reflected in**
15 **the design of PGE's PCAM. Should these principles be revisited?**

16 A. Yes, particularly when viewed in the context of our peer group utilities. The current PCAM,
17 coupled with a failure to grant a compensating increase in the authorized ROE for the
18 additional risk PGE faces creates a disadvantage to the company in raising capital. The
19 appropriate principles for the development of a PCAM are discussed in PGE Exhibit 1300.

IV. Qualifications

1 **Q. Please describe your educational background and experience?**

2 A. I received my Bachelor of Arts degree from Georgetown University in 1987 and my
3 Master's degree in Business Administration from the Stanford University Graduate School
4 of Business in 1992. I was named Senior Vice President, Chief Financial Officer and
5 Treasurer in January 2009. From January 2006 through December 2008, I served on the
6 PGE Board of Directors. Previous to January 2009, I served as Vice President, Chief
7 Financial Officer at Mentor Graphics Corp., an Oregon-based software company, where I
8 was responsible for multiple departments including the company's financial affairs,
9 corporate development and operations. Before I joined Mentor Graphics in 2007, I served 12
10 years in a variety of capacities at Pope & Talbot, Inc, and worked previously at Morgan
11 Stanley.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
201	Pacific Economics Group Final Report
202	Benchmarking Inventory
203	Operational Efficiencies