UE 335 / PGE / 100
Pope – Lobdell

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Maria Pope
Jim Lobdell

February 15, 2018

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Maria Pope. I am the President and Chief Executive Officer of PGE.

My name is Jim Lobdell. I am the Senior Vice President of Finance, Chief Financial Officer, and Treasurer of PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Describe the context of this filing and our customers' expectations;
- Discuss PGE's operational excellence and continuous improvement efforts;
- Summarize the proposed average price increase of approximately 4.8% and discuss our efforts to mitigate the impact of the price increase, in keeping with our long-term strategy of providing affordable and safe energy for customers; and
- Identify our other key proposals.

Our testimony is organized according to these objectives.

Q. Please provide a brief description of PGE.

A. PGE is a vertically-integrated regulated electric utility company. We proudly serve more than 870,000 customers in 51 cities within Oregon, including the City of Portland, which is one of the fastest growing regions in the country. With more than 2,900 employees across the state as of December 31, 2017, we are committed to building a cleaner, more reliable, and more efficient energy future. Given our customers' interests, we have the number one voluntary renewable energy program in the country. Certain cities in our service territory have proclaimed resolutions to move to 100% renewable power, and more than 170,000 PGE customers voluntarily participate in our renewable power program.

Our service territory includes 4,000 square miles, primarily in and around the Portland and Salem metropolitan areas, and we are headquartered in Portland, Oregon.

Q. Please state PGE's mission and core strategy.

A. For more than 128 years, we have been delivering safe, reliable and affordable energy to Oregonians. Today, our industry is faced with new challenges driven by changing customer expectations and rapidly evolving technology. In addition to safe, reliable and affordable energy, customers today also want their energy to be cleaner and more secure. By cleaner, we mean that our customers want us to reduce carbon emissions; by more secure, we mean that the grid and our systems are secure from physical and cyber-attacks.

During the past year, PGE's officer team has been working together to update our company strategy to guide us towards achieving the needs and expectations of our customers and other stakeholders. As a result, we have revitalized our Strategic Direction with four key strategies to address our customers' changing expectations. Our strategies include:

- **Deliver** exceptional customer experiences;
- **Invest** in a reliable and clean energy future;
- **Build** a smarter, more resilient grid; and
- **Pursue** excellence in our work.

Q. How do you manage the company to PGE's mission and core strategy?

A. First, employees have to understand and embrace the Strategic Direction and what it means for our work. We have been meeting with employees around the company to discuss the refreshed strategy and answer questions. This is an important piece of building culture and employee buy-in. In terms of the day-to-day work, we use scorecards with clearly stated goals and metrics for evaluating progress against our strategies. The scorecards also include improvement plans for controlling our costs, improving our efficiency, and improving the customer experience.

II. Context and Customers' Expectations

Q. What are your goals for PGE?

A. First and foremost: to deliver safe, reliable, affordable, clean, and secure energy to our customers with excellent customer service while complying with all applicable laws and regulations. Our company values guide how we do this and reflect our commitment to our customers, employees, community, and shareholders. As we are successful, we will: 1) be viewed by our customers as their most trusted energy partner; 2) be a preferred employer, attracting and retaining exceptional employee talent; 3) maintain our standing as a caring and invested community partner; and 4) attract capital investors by offering a competitive return on capital invested and maintaining our investment-grade ratings.

Q. What does your most recent research tell you about your customer expectations and priorities?

A. The top three priorities for PGE customer are outage restoration, affordable rates, and generation of energy using environmentally-friendly resources.

Additionally, , more than 80% of our customers say that the following are "very important" expectations they have of PGE:

- Protect grid from cyber-attacks and other threats;
- Minimize outages; and
- Provide great customer service.

Q. How are changing customer demographics and the increased reliance on digital products affecting your customers' expectations?

A. Our research shows the following characteristics about PGE's customers and electricity customers in the United.States. in general:

- Millennials and successive generations already comprise about one quarter of PGE's customer base. It’s expected that they will comprise half (or more) of Oregon's population within 10 years;
- Most PGE customers (73%) provide us with a mobile phone number rather than a landline. This demonstrates our customers' preference for mobile devices as a channel of contact and engagement;
- Younger customers (Millennials/Generation Y) contact their electric utility two to three times as often as customers of other generations; and
- Younger customers also use a much wider variety of methods/channels to engage with their electric utility.

Q. How important is reliability to your customers and to U.S. electricity customers in general?

A. From PGE’s participation in the JD Power Electric Utility Business Customer Satisfaction surveys we’ve learned that:

- Reliability is one of the most important drivers of customers' satisfaction with their electric utility;
- The importance of reliability in the JD Power model has increased four percentage points in the last 10 years (2007 model to 2017 model); and
- When PGE does not meet our customers’ reliability and outage restoration expectations, overall satisfaction declines. Performing poorly on reliability and outage restoration today is even more impactful than it was 10 years ago. This indicates customers are less tolerant of shortfalls (have higher performance

expectations) today compared to 2007. This pattern is evident for the industry overall and can be more pronounced among PGE customers.

Q. What are you doing to meet your commitments to your customers?

A. We are balancing the safety, service, reliability, and security our customers expect with keeping energy prices affordable. We do this by focusing on:

- Providing a safe and reliable power supply with resources sufficient to meet peak demands;
- Replacing infrastructure that has reached the end of its useful life, such that it threatens system reliability and safety;
- Protecting our system from external physical and cyber threats;
- Responding quickly to outages, account services requests, and inquiries;
- Providing excellent customer service; and
- Implementing programs designed to enhance customer options and experience, and using proven technology to test customer interest and participation, while weighing the costs and benefits.

Q. How do your customers' changing expectations influence the services PGE delivers and associated costs?

A. In order to provide the services customers expect, our systems are experiencing significant and continuous evolution, and are now more connected and integrated than ever before. In addition to dedicating more resources to keep the lights on, we also require incremental resources to provide smarter cyber capabilities with safe security platforms. In 2017, our Information Security Program developed a comprehensive, tiered governance model for the security program that encompasses all business units. PGE Exhibit 600 discusses these issues and their incremental costs in more detail.

Q. In addition to the need to respond to changing customer expectations, how do economic conditions impact PGE?

A. Economic activity in our service territory has been driving in-migration, growing customer count, and increasing customer connects and demands on our systems. These activities generate an increase in customer calls, especially during outages, and a higher overall volume of work.

Q. How is energy efficiency affecting PGE's load growth?

A. Typically, customer count growth results in load growth. However, as shown in our recent integrated resource plans, energy efficiency is partially offsetting load growth that would otherwise be expected to accompany population and economic expansion. The Energy Trust of Oregon expects to achieve incremental energy efficiency savings of 1.6% of net system load or 34 MWa in 2019, which is in addition to significant non-sponsored energy efficiency savings achieved by our customers.

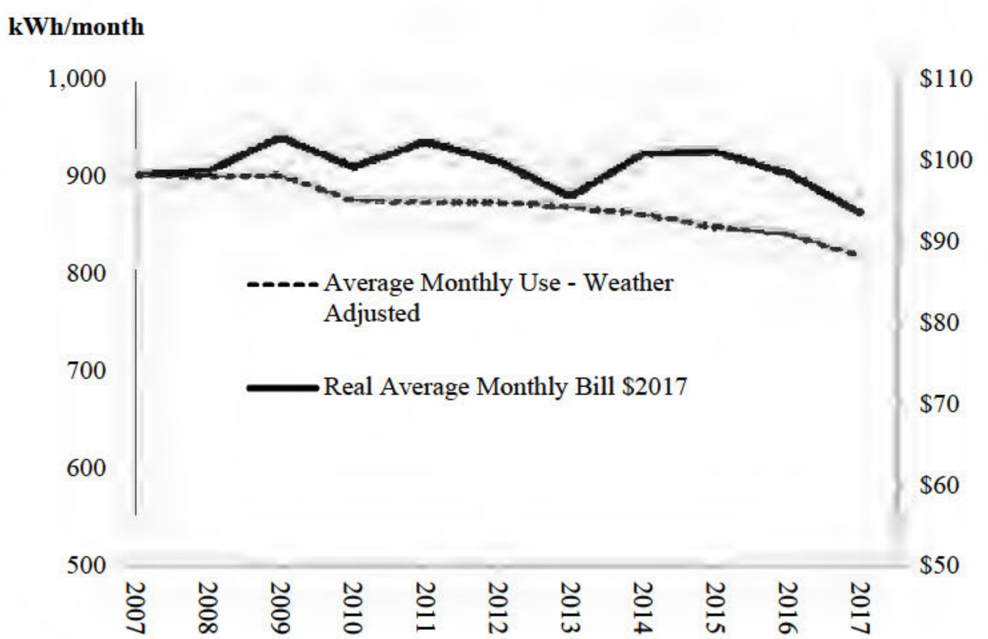
Q. Over the longer term, does modest load growth and increasing energy efficiency create regulatory challenges?

A. Yes. Historically for PGE, as well as the industry as a whole, growth in retail loads produced net margin that enabled us to absorb normal inflationary cost increases and incremental fixed costs. As load growth slows, we are faced with a need to increase customer prices, such that forecast revenues and forecast costs are alignedin order to allow for the opportunity to earn a reasonable return and maintain access to lower cost capital markets.

Q. Does PGE support energy efficiency?

A. Yes. We support cost effective energy efficiency because it benefits our customers and our service area in many ways. In addition to being better for the environment, energy efficiency decreases the need for adding new resources to the system, maintain lower costs for customers. Even as the price per kilowatt hour goes up, a reduction in total kilowatt hours used by the average customer helps to offset the bill impact. Figure 1 below, shows that average inflation-adjusted residential bills were roughly the same in 2007 and 2017. Energy efficiency has reduced average monthly residential usage by 9% over the same time period.

Figure 1
Average Residential Use and Bill 2007-2017



III. Operational Excellence and Continuous Improvement

Q. Please discuss PGE's pursuit of operational excellence.

A. We pursue operational excellence in all aspects of our business. Operational excellence begins with keeping our customers, employees, and the general public safe as it relates to our electric infrastructure, as well as providing excellent customer service and reliability in our transmission, distribution, generation, and power operations. We are working to meet our customers' expectations, and our customers are taking notice. According to the JD Power 2017 Electric Utility Business Customer Satisfaction Study, our customers ranked us Number one among large electric utilities in the Western region.

To deliver the service customers expect and rely on, we have several initiatives to support operational excellence, including:

- **Customer Engagement Transformation (CET):** A multi-year implementation of a program focused on process improvements, business strategies, operational efficiencies, employee development, and replacement of our Customer Information System (CIS) and Meter Data Management System (MDMS). PGE Exhibit 900 provides additional details.
- **Transmission and Distribution (T&D) system capital investments:** As discussed in Docket No. UE 319 (UE 319), we are increasing capital investments in our T&D system due to increasing customer-driven work and the need to improve our T&D system to keep it safe and reliable. The capital improvements will enable us to meet our goals and our customers' expectations related to the reliability, safety, environmental stewardship, and cost effectiveness of the T&D system. PGE Exhibit 800 provides additional details.

- **Western Energy Imbalance Market (Western EIM) participation:** During 2017, PGE joined the Western EIM, which is a real-time wholesale energy market that automatically dispatches the lowest-cost electricity resources, while optimizing use of renewable energy over a large geographic area. We are now focused on Western EIM enhancements, and analyzing participation in the potential expansion of the California Independent System Operator's day-ahead market. PGE Exhibit 300 provides additional details.
- **Information Technology (IT) systems investments:** These systems are becoming increasingly more critical to all aspects of our operations (with increasing scope, reliance, and use) and we expect this trend to continue in 2019 and beyond. In addition, the threats against these systems have increased significantly and become more sophisticated and far reaching. As a result, the level, severity, and consequence of the cyber threat to critical infrastructure providers such as utilities is rapidly increasing. PGE Exhibit 600 provides additional details.

Q. In addition to operational excellence, you mentioned continuous improvement. How is PGE continuously improving?

A. Continuous improvement is every employee's responsibility. All management and individual contributors across the organization are constantly tasked with identifying process improvements and opportunities to avoid costs.

Q. Please explain PGE's continuous improvement cycle.

A. We remain committed to our continuous improvement cycle and to becoming more efficient and effective in our day-to-day activities. The ultimate responsibility to continually improve is with all our officers and managers. These efforts include benchmarking, which we use to help each functional area understand how we compare to peer companies, identifying best practices, determining areas to improve based on a business case, and implementing our operational efficiency and effectiveness initiatives. These changes typically address improvements for people, processes and/or technology. As discussed in prior General Rate Cases (Docket Nos. UE 262, UE 283, UE 294, and UE 319), we conduct periodic benchmarking to identify areas for improvement and best practices. PGE Exhibit 101 shows the functional areas scheduled to conduct benchmarking studies in 2018 and 2019.

Q. How long will this benchmarking effort continue?

A. We intend to continue this process for the foreseeable future as part of our corporate Strategic Direction. Our continuous improvement process is an ongoing effort with incremental savings or avoided costs expected over multiple years. In the next section of our testimony, we provide examples of the savings included in our 2019 test year revenue requirement.

IV. Summary of Request

Q. Please summarize PGE's request in this rate case filing.

A. We request that prices be adjusted to yield $85.9 million of additional revenues, which represents a 4.8% increase overall for cost of service and direct access customers beginning January 1, 2019 (PGE Exhibits 200 and 1300 provide additional details).

Additionally, our request includes the impact from the 2017 federal tax legislation[1] (Tax Reform), and new and renewed policy tools to better balance risk and manage price impacts over time, including:

1. A request to extend the decoupling mechanism currently slated to expire at the end of the 2019 test year for an additional three years, along with certain modifications to the mechanism as described in PGE Exhibit 1300.
2. A request for changes to PGE's long-term direct access program as described in PGE Exhibit 1300. The changes are:
    - Modify Schedule 129 transition adjustments to reflect fixed generation costs over ten years, with annual updates to fixed generation costs to reflect actual costs; and
    - Allow PGE to petition the Public Utility Commission of Oregon to decertify an Electricity Service Supplier if they do not follow scheduling practices.
3. A request to create a balancing account for major storm restoration costs as described in PGE Exhibit 800. PGE has recently experienced greater volatility in year-to-year restoration costs, and our proposal is designed to allow for a better

[1] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018. Public Law Number 115-97.

opportunity for PGE to recover its prudently incurred costs and meet our customers' expectations for quick, effective restoration of service, while also managing customer price impacts associated with this greater cost volatility.

4. A request, as described in PGE Exhibit 300, to track and true up the forecasted power cost impacts of the difference between:
   - The forecasted online date for new Qualifying Facilities as used in MONET's[2] Net Variable Power Cost (NVPC) forecast; and
   - The actual on-line date.

Q. What are the primary elements of PGE's filing?

A. Our request is centered on keeping our system safe, reliable, and secure and meeting our customers' expectations for quality service. The specific drivers include:

- Building a smarter, more resilient grid to support our current customers and growth in our region, while maintaining the safety and reliability our customers count on, including:
  - Strategic Capital Improvements for Customer Risk Reduction – We are upgrading our T&D system, including replacing infrastructure that is reaching the end of its useful life. As described in PGE Exhibit 800, these projects will allow PGE to mitigate significant reliability risks for customers in the T&D system related to aging and environmentally hazardous substation assets, aging conductors in the distribution system, and external causes of service failures in the distribution system (e.g., weather events and vegetation).

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[2] MONET is PGE's Multi-area Optimization Network Energy Transaction model used for power cost forecasting.

  - Customer-Driven Capital Work – T&D is seeing an increase in customer-driven capital work, primarily in new customer connections. To keep up with increasing customer demand, T&D is having to increase its capital labor to support the upgrade and expansion of existing infrastructure, as well as building new ones (e.g., substations). PGE Exhibit 800 discusses this in more detail.

- Strengthening our IT systems to better guard against cyber-attacks and other potential threats. Given the significant increase in threat to the electric sector and the consequences of an intrusion, we are accelerating the implementation timeline associated with the Information Security Program. At the same time, we are embracing and preparing the foundation for expanded cloud-based services. PGE Exhibit 600 discusses this in more detail.
- Upgrading our customer service and billing systems and processes to provide better, more secure service to customers. As outlined in PGE Exhibit 900, our CET program includes a necessary system upgrade that will allow us to serve our customers more effectively and efficiently, and increase protections against cyber threats. It focuses on process improvements, business strategies, operational efficiencies, employee development, and replacement of our outdated CIS and MDMS.
- An initial NVPC forecast represents an increase of approximately $39 million. PGE Exhibit 300 discusses this in more detail.

- Higher Property Taxes due to an increase in plant assets, including a full year of Carty Strategic Investment Program, and higher Montana levy rates for Colstrip. PGE Exhibit 200 discusses this in more detail.
- About $14 million in reduced revenues based on lower forecasted energy sales. PGE Exhibit 1100 shows our loads are forecasted to decrease in 2019 relative to the forecast used to set prices for 2018. Without resetting prices, we will experience lower revenues and not fully recover our costs.

Q. Please describe the specific impacts of the recent Tax Reform.

A. The Tax Reform includes provisions that directly and indirectly affect PGE's revenue requirement. The most important provision is the lowering of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. This has the immediate effect of reducing PGE's current and deferred income tax expense. Additional impacts on PGE's 2019 revenue requirement consist of:

- Reduction of PGE's accumulated deferred income tax (ADIT) liability;
- Elimination of the Domestic Production Activities Deduction;
- Adjustment of production tax credits (PTCs) in power costs due to the lower gross-up for taxes; and
- Inclusion of the Excess ADIT reversal.

PGE Exhibit 200 discusses this in more detail.

Q. Has PGE submitted any other filings in relation to the Tax Reform?

A. Yes. On December 29, 2017, PGE filed for deferred accounting treatment for the expected 2017 and 2018 net benefits associated with the provisions implemented through the

Tax Reform. Because of the length and complexity of the legislation, PGE will continue to evaluate the Tax Reform's implications.

Q. What actions has PGE taken to mitigate the price increase in this rate case?

A. As our business grows, we work to manage costs and offset the impacts of inflation and other prudent cost increases. To accomplish this, we have taken a number of specific actions including:

- Removing 100% of forecasted Officer Long-term Incentive Program costs and 50% of all other forecasted incentive compensation costs, even though the entirety of the incentive program benefits customers and is a key part of all investor owned utilities' total compensation.
- Removing 50% of certain layers of directors' and officers' insurance.
- Requesting a return on equity (ROE) in the lower portion of the range supported by our expert witness Dr. Villadsen. We are proposing a 9.5% ROE consistent with the final result in UE 319, even though interest rates are rising. However, a higher ROE rate would be justified by our expert witness. Dr. Villadsen's range of estimates is between 9.2% and 11.1% and is based on her sample using several methodologies. PGE Exhibit 1000 provides additional details.
- Removing certain costs through our rigorous budget process. Additional details are provided below.

Q. You mentioned cost management. How does this rate case reflect your commitment to managing your costs?

A. This case reflects the savings achieved through our continuous improvement efforts including some of the ongoing projects discussed above. As described in the Operational

Excellence and Continuous Improvement section, our employees' efforts and the use of continuous improvement cycles demonstrate our commitment to managing costs, streamlining processes, learning from others, and creating a culture of continuous improvement at PGE that benefits customers through improved service and reduced long-term cost impacts.

At the same time, incorporating cloud-based services in the future will provide us with a new level of flexibility in how we manage and organize our IT capabilities. We expect that utilizing cloud-based services instead of traditional data center services provides more stability and predictability for IT costs. The use of technology has the ability to increase efficiency and reduce enterprise risk, as well as increase financial transparency and enable more informed financial decisions.

Q. Please provide specific examples of how PGE manages its costs.

A. We have provided significant detail in recent years to quantify benefits to customers for the programs, systems, and initiatives being implemented. Please refer to PGE's response to OPUC Data Request No. 558 in UE 319 (provided here as PGE Exhibit 102).

Additionally, our 2019 test year includes the following significant cost reductions incorporated into our budget process:

- Customer Service Operations - CET program related:
    - Reduction of 5.5 full time equivalent employees (FTE) after the systems are stable and operating.
    - Reduction of 5.7 FTEs due to the conclusion of the program management office.
    - Paperless Billing: $276,000 reduction to the cost of postage and envelopes.

- T&D: $1.1 million in lower Contract Labor and Outside Services.
- Corporate: $2.5 million annual decrease in the World Trade Center lease agreement.

Q. What are the proposed price impacts to various customer schedules in the 2019 test year?

A. Similar to UE 319 and due to increases in distribution and IT costs in this rate case, customer classes that use these services more intensively bear a higher burden for the costs, as demonstrated in PGE Exhibit 1300. Table 1 below shows the proposed price changes associated with this case.

Table 1

Estimated Cost of Service Base Rate Impacts Inclusive of Schedule 122

Schedule	**Jan. 1, 2019**
Schedule 7 Residential	6.3%
Schedule 32 Small Nonresidential	7.1%
Schedule 83 31-200 kW	3.8%
Schedule 85 201-4,000 kW	1.2%
Schedule 89 Over 4,000 kW	2.1%
Schedule 90 100 MWa	3.2%
Cost of Service and Direct Access Overall	4.8%

V. Other Elements of This Filing

Q. What other elements are included in this rate case?

A. Our case includes the following:

- A forecasted capital structure of 50% equity and 50% debt to allow us to maintain our stable, investment grade credit rating, which will provide the financial strength necessary to allow us access to capital markets, make ongoing investment in our system, and provide access to wholesale fuel and power markets.
- An increase in the monthly customer charge so that we can recover more of our fixed costs through fixed charges: Residential by $2.00 per month; small commercial, Schedule 32 single-phase service, by $3.00 per month; and small commercial, Schedule 32 poly-phase service, by $6.00 per month. This increase balances the need for fixed-cost recovery, with the principle that the volumetric energy prices provide a price signal for customers to conserve energy.

Q. Will the results of this rate case affect PGE's access to and cost of capital to fund investments in the near future?

A. Yes. The results of this case, as filed, will provide us with the opportunity to fund capital investments, meet our financial obligations, and provide an opportunity for our shareholders to receive a reasonable return on their investment. An unfavorable result in this case could lead to higher interest rates on debt issuances and an inability to attract equity capital at a reasonable price, which eventually would raise costs to customers.

Q. Are there other risks of changes to your requested price increase that are not currently factored in the costs for the 2019 test year filing?

A. Yes. The Commission is currently running a proceeding to consider changes to the utility business and regulatory models and meet its reporting mandate to the legislature by September 2018, as required by Senate Bill 978. Commission or legislative changes to the business or regulatory models could create substantial impacts on PGE's cost and revenue structures. We have developed the 2019 test year within the context of the current regulatory model and PGE's operations within that model.

Additionally, the legislature's short session commenced in February 2018 and the legislature could enact legislation that impacts our business and costs. One key piece of legislation being discussed for action in 2018 is carbon regulation.

VI. Structure of PGE's Filing

Q. How is PGE presenting this case?

A. We are presenting the following direct testimony:

- In Exhibit 200, Alex Tooman, Senior Regulatory Consultant, and Marco Espinoza, Senior Regulatory Analyst, summarize the overall 2019 test year revenue requirement, comparing the request with the 2017 actuals. This testimony also discusses our rate base at year-end 2018, plus associated depreciation and amortization, and unbundled results.
- In Exhibit 300, Managers Mike Niman and Cathy Kim, and Greg Batzler, Senior Regulatory Analyst, provide the initial forecast of our NVPC, discuss updates to parameters and modeling changes, compare the forecast with the final 2018 NVPC forecast, and explain why the per-unit expected NVPC have increased.
- In Exhibit 400, Anne Mersereau, Vice President, Human Resources, Diversity & Inclusion, and Tamara Neitzke, Director of Compensation and Benefits, present our compensation costs for the 2019 test year.
- In Exhibit 500, Jim Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, and Greg Batzler, Senior Regulatory Analyst, explain our costs and cost drivers related to corporate support operations, including insurance and research and development.
- In Exhibit 600, Larry Buttress, Interim Vice President and Chief Information Officer, explains our costs and cost drivers related to IT and cyber security.
- In Exhibit 700, Bradley Jenkins, Vice President of Power Supply Generation, and Stefan Cristea, Regulatory Analyst, support operations and maintenance (O&M)

costs associated with our power supply resources. This joint testimony also discusses recent plant performance.

- In Exhibit 800, Bill Nicholson, Senior Vice President of Customer Service, T&D, and Larry Bekkedahl, Vice President of T&D, explain our 2019 test year transmission and distribution O&M expenses and capital improvement efforts that will allow us to maintain and enhance our T&D system, discuss our request to modify the current storm accrual, and request the Commission to approve our 2017 storm deferral application.
- In Exhibit 900, Kristin Stathis, Vice President of Customer Service Operations, and Carol Dillin, Vice President of Customer Strategies and Business Development provide a detailed update of the CET program and describe the initiatives that support the customer experience. They also explain customer service O&M costs for the 2019 test year.
- In Exhibit 1000:
    - Patrick Hager, Manager of Regulatory Affairs, and Chris Liddle, Corporate Finance and Investor Relations Manager & Assistant Treasurer, recommend our cost of capital and capital structure for the 2019 test year; and
    - Bente Villadsen, economist and principal at The Brattle Group, estimates our required ROE and describes the supporting analyses.
- In Exhibit 1100, Amber Riter, Principal Load Forecasting Analyst, and Alison Lucas, Senior Load Forecasting Analyst, provide the initial load forecast and explain the process and method in forecasting the 2019 test year load.

- In Exhibit 1200, Robert Macfarlane, Interim Manager, Pricing and Tariffs and Jacob Goodspeed, Senior Regulatory Analyst, describe marginal cost studies for generation, transmission, distribution, customer service, and street lighting.
- In Exhibit 1300, Robert Macfarlane, Interim Manager, Pricing and Tariffs, and Jacob Goodspeed, Senior Regulatory Analyst, describe how the proposed tariff changes recover our 2019 revenue requirement to achieve fair, just, and reasonable prices for our customers and price changes to various supplemental schedules.

VII. Qualifications

Q. Ms. Pope, please describe your educational background and experience.

A. I am an alumna of the Stanford Graduate School of Business and earned my bachelor's degree from Georgetown University. Prior to joining PGE, I was the chief financial officer of Mentor Graphics Corporation and served in senior operating and finance positions within the forest products and consumer products industries. I joined PGE in 2009 as Senior Vice President of Finance, Chief Financial Officer and Treasurer after serving two years on our board of directors. Most recently, I was the Senior Vice President of Power Supply, Operations and Resource Strategy, overseeing our power supply portfolio, operations — including wholesale power, fuels, marketing, trading and long-term resource strategy — and generation facilities, including 17 thermal, hydro and wind facilities. I entered my current position as President in October 2017 and CEO and member of the board in 2018.

I was appointed by Oregon's governor to chair the Oregon Health & Science University governing board, and I serve on the board of Umpqua Holdings Corporation. I have previously served on several other U.S. and Canadian boards.

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 as a business analyst in 1984, I have held a variety of positions at PGE and its affiliates. I was senior director of Business Development, director of Internal Audit Services and manager of Financial Risk Management & Pricing, where I provided financial risk management for our wholesale electric and natural gas portfolios. I then served as Vice President of Power Operations and Vice President of Risk Management, Reporting, and Controls & Credit. In 2004, I was named Vice President of Power Operations and Resource

Strategy. I entered my current position as Senior Vice President, Finance, Chief Financial Officer, and Treasurer in March 2013.

I am a member of the FM Global Advisory Committee, Treasurer of the PGE Foundation, advisory member of the University of Oregon Portland Council, and board member of the ALS Association of Oregon and SW Washington.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Projected Benchmarking Study Schedule

Dept / Data Year	2018	2019
Finance (F&A)		Planned Benchmark
Transmission & Distribution (T&D)	Planned Benchmark	
Information Technology (IT)		Planned Benchmark
Customer Service		Planned Benchmark
Fleet	Utilimarc	Utilimarc

May 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 558
Dated May 9, 2017

Request:

Referring to the Company's UE 319 excel work sheet 2014-2018_FTE_W&S_By Operation,RC & Class_01-30-17.xls, at 13-18, UE 294 *I* PGE *I* 500, Barnett-Jaramillo/16-17, UE 294 *I* PGE *I* 600, Lobdell - Henderson - Tooman *I* 28 -36, UE 294 *I* PGE *I* 800, Nicholson - Bekkedahl *I* 12, UE 294 *I* PGE *I* 900, Stathis - Dillin *I* 8-13.

Please provide a narrative explaining why the Company's FTE count, including the FTE allocated to the CET deferral, has increased by 302.2 FTE in 2018 over 2016. In the response, please include:

a. Any and all studies or similar deliverables, whether conducted by consultants or internally, initiated from 2014 to present such as benchmarking studies, management reports, variance analysis, cost report cards, etc. that quantify the gained efficiencies since 2014 and provide evidence that these programs and initiatives are benefiting customers.

Response:

Narratives explaining the referenced increase in PGE's FTE count have been provided in UE 319 testimony, supporting exhibits, and in numerous responses to data requests. All references to this information is summarized in Attachment 558-A. FTE increases by project will also be provided in PGE's response to OPUC Data Request No. 561, Attachment 561-A.

a. PGE has provided significant detail in recent years to quantify benefits to customers for the programs, systems, and initiatives being implemented. We summarize these benefits as follows:

1. In PGE's 2014 general rate case (GRC – Docket No. UE 262), we identified significant savings from improvement initiatives. These savings were summarized in PGE Exhibit 201 (provided as Attachment 558-B), which also lists the testimony reference where the savings were discussed in more detail. PGE Exhibit 200 (UE 262, pages 6-10) also included a summary description of the $15.6 million in annual, on-going savings, which is provided as follows:

PGE has numerous improvement initiatives completed or underway as a result of our benchmarking activities, process improvements, or other activities. Some of these major initiatives are:

- Transmission & Distribution (T&D) Transformation is an effort to improve work processes and leverage technology to improve safety, accountability, standardization, productivity, and efficiency in transmission and distribution. The transformation program projects O&M annual savings of $3.4 million in 2014. Details can be found in PGE Exhibit 800, Section II.
- Financial Systems Replacement Project (FSRP) replaced PGE's obsolete 26-year old Masterpiece system with a new financial system that enables streamlined workflow and automation of many manual processes. Examples of streamlined workflow include:
    - 40% reduction in cash management processing time; and,
    - Automation of 80% of book-tax adjustments.

  FSRP, in conjunction with Lean process analysis, allowed for Finance and Accounting (F&A) to realize efficiencies through a net reduction of approximately 11 Full Time Equivalents (FTE) through 2012 and another 4.3 FTEs by 2014. Details can be found in PGE Exhibit 1000, Section II, Part A.
- Procurement Efficiencies via Strategic Sourcing consists of performing spend analysis by utilizing our new financial system (FSRP), identifying business requirements, understanding the marketplace, developing a supply category strategy, evaluating and selecting suppliers, negotiating agreements, developing scorecards to measure supplier performance and then repeating the process to drive continuous improvement. In 2012, PGE negotiated over $7.6 million of O&M cost savings and $2.6 million of O&M avoided costs that span multiple years (i.e., $1.4 million in 2012, $1.2 million in 2013, $1.1 million in 2014, and the remaining $6.5 million after 2014). Details can be found in PGE Exhibit 1000, Section II, Part A.
- Lean Processing in Human Resources – Lean processing is a process improvement methodology that focuses on removing "waste" from processes so that efficiencies in time and resources can be achieved. Waste can be anything from wait time, to errors and re-work, to extra processing. As processes are improved, productive resources can be reallocated to higher-value activities. PGE's Human Resources (HR) has completed 20 Lean processes with more in progress. Details on HR Lean processing efforts can be found in PGE Exhibit 1000, Section II, Part C.

- Employee Benefit Provision Mitigation – Health care reform will have a significant impact on medical plan design and cost as it evolves over the next few years. PGE is monitoring health care reform, and we are evaluating possible future changes to existing benefit plans. In preparation for reform, we have modified many benefit provisions to offset the full effect of increases in benefit costs while maintaining an effective level of benefit support for employees. Some of the benefit changes are:
  - Increasing deductibles and co-pays;
  - Adding additional coinsurance to various plans; and,
  - Offering high deductible plans by each vendor in addition, not in lieu of other offerings.

  PGE evaluates if a change in benefit options offered is prudent and if further cost shifting to employees, in terms of out-of-pocket contributions, deductibles and choices of care are appropriate. See PGE Exhibit 500, Section IV for more details on how PGE is working to mitigate benefit cost increases.
- myTime is a web based time collection system (TCS) that will increase accuracy and reduce resources spent on time-keeping processes and payroll. myTime will replace the currently obsolete paper TCS in 2013. PGE projects a reduction in payroll costs of $1.0 million, which is reflected in wages and salaries in both 2013 and 2014. myTime is explained in more detail in PGE Exhibit 1000, Section II, Part C.
- Information Technology (IT) Vision Design is a roadmap of 15 initiatives directed at improving IT's effectiveness, capabilities, and efficiency over the next three years. Each initiative encompasses one or more of the following six foundational principals: partner with the business; eliminate complexity; source strategically; standardize IT process/procedures; build a strong workforce; and, meet increasing service expectations. Through the 15 initiatives, IT will be able to continue supporting PGE's growing need for technical infrastructure and services while maintaining a relatively flat IT employee count. From 2011 through 2014, we project a net reduction of 7.8 IT FTEs. See PGE Exhibit 600, Section III, Part B for details.
- Generation Excellence. In 2006, PGE's generation organization established the Generation Excellence initiative to focus on improvement efforts such as safety, employee performance, process improvements, and reliability. Generation Excellence has continued to evolve with the establishment of Reliability and Maintenance Excellence (R&ME), which is a comprehensive approach to reliability and maintenance; it encompasses, and better aligns, several sub-initiatives including Reliability Centered Maintenance (RCM) and utilization of our Enterprise Work and Asset Management System (Maximo). R&ME is plant specific and each plant is anticipated to have their strategy in place by the end of 2013. For more detail see PGE Exhibit 700, Section III, Part A.

2. In PGE's 2015 GRC (UE 283), we updated the UE 262 savings plus identified incremental amounts that totaled to $23.4 million in cumulative annual savings. We summarized these benefits in PGE Exhibit 707 (UE 283) and provide them as Attachment 558-C. Additional detail regarding benefits from the Transmission and Distribution Transformation project (part of PGE's 2020 Vision program) can be summarized as follows:

   Maximo, Mobile & Scheduling improves employee safety, heightens accountability, and standardizes our processes, which improves productivity and efficiency in the following ways:

   - Employee Safety: With mobile devices in the hands of field workers, PGE is able to track work processes being performed and logged when a worker is completing an inspection or doing maintenance work in real-time. The Mobile & Scheduling tools improve employee safety by providing PGE with real-time updates on the location of our field workers and provide a communication link in the field.
   - Accountability: Maximo, Mobile & Scheduling provides teams with better accountability data and production information. Supervisors have the ability to review the current status of field crews and details of assigned work. Field workers can update the status of their work, resulting in real-time data for schedulers and supervisors. By having an enterprise wide work and asset management system, we have a clearer, more integrated view of how and where work is being performed within PGE and how to more effectively employ our company personnel and assets.
   - Productivity: Productivity should increase as work orders are created in Maximo, and electronically routed and dispatched along with the field workers (including contractors) who are closest to the worksite and possess the appropriate skillset(s) to perform the work. The new technology provides workers with real-time customer and asset information. Mobile & Scheduling tools provide:
     - Optimization of scheduling to reduce travel time and crew costs;
     - An opportunity to re-optimize work schedules dynamically, as needed;
     - Real-time dispatching of work details and status updates; and
     - Automatic asset information updates and work order closures.
   - Efficiency: In addition to allowing PGE to track purchasing of inventory stores and materials for work orders, Maximo also provides PGE with the ability to track the rate of use of inventory to optimize stock levels. PGE's goal is to maximize availability of items required for upcoming work while also reducing or removing, as may be appropriate, inventory that is required less frequently or has become obsolete. The reduction in inventory is also expected to reduce the carrying costs associated with that inventory.

3. In PGE's response to OPUC Data Request No. 489, part d, we identified an additional $3 million to $5 million in savings associated with PGEs' customer engagement transformation program (CET) based on:

- A reduction of 33 FTEs between 2013 and 2016, which has allowed the customer service organization to reduce its FTE count from 407 in 2012 to the projected 382 in 2018 with some offsetting increases due to other factors such as customer growth.
- An additional 10.9 FTE reduction is projected in 2019/2020 after the system is stable and operating.
- Approximately $1.0 million in non-labor cost reductions due to the paperless billing program. This savings will grow as customer participation in the program increases.

4. In addition to the savings listed above, PGE had also identified additional savings as discussed in the following proceedings:

- In UE 294 (2016 test year GRC, PGE Exhibit 700), PGE reduced its annual production O&M by $4.5 million based on a change in the maintenance and repair program for the Biglow Canyon wind farm.
- In UM 1756, PGE deferred for later refund an annual $1.3 million for the reduced debt cost associated with the issuance of $140 million in debt in January 2016.
- In UE 294 (2016 test year GRC, PGE Exhibit 400), PGE discussed the benefits associated with more frequent scheduling and dispatch of PGE's plants. At that time, managing the intra-hour variability of our wind resources on a 15-minute basis (i.e., 30/15 committed scheduling under BPA's Variable Energy Resource Balancing Service) reduced PGE's initial 2016 power cost forecast by approximately $2.9 million. In UE 319, PGE identified the benefits of moving off of 30/15 committed scheduling as an additional $2.1 million decrease to PGE's 2018 power cost forecast, net of costs associated with incremental reserve needs to fully self-integrate PGE's owned wind resources.
- In UE 308 (2017 power cost AUT filing, PGE Exhibit 400) PGE discussed the benefits associated with joining the Western energy imbalance market (Western EIM). The Western EIM is expected to produce several benefits, including sub-hourly dispatch savings, flexible reserve savings, and reliability benefits. Based on a study by Energy + Environmental Economics (E3 – provided as PGE Exhibit 402 in UE 308) the gross savings associated with these benefits was estimated to be $3.5 million in a 2020 base scenario. In UE 319, PGE provided an updated E3 study (provided as PGE Exhibit 303), which estimated $5.2 million for similar gross benefits in a 2018 base scenario. Including all costs and benefits associated with Western EIM participation, PGE's net benefit is approximately $1.0 million in 2018 (see Table 1 of PGE Exhibit 300).

- In UE 189, PGE's submitted its final report to the Commission (November 2, 2012) on actual operational savings derived from PGE's advance metering infrastructure system. The report stated that annual savings totaled $19.0 million and were expected to increase in 2013.

5. Additional discussion regarding other benefits to customers (i.e., not in the form of hard savings) has been provided in the following testimony as well as regular presentations to the OPUC Staff in advance of each of the past four general rate cases (GRCs).

   i. The 2020 Vision project has been discussed in Information Technology testimony in each of the last five GRCs (PGE Exhibit 600, UE 215; PGE Exhibit 600, UE 262; PGE Exhibit 700, UE 283; PGE Exhibit 600, UE 294; and PGE Exhibit 500, UE 319). Detail regarding benefits can be summarized as follows (see PGE Exhibit 600, UE 215, pages 24-28):

   - Current technology obsolescence – Many of the systems that PGE plans to replace have been in service for many years and are either no longer supported by the vendor or will not be supported in the near future. When systems are no longer supported, upgrades and enhancements are no longer provided by the vendor to meet new requirements, patch security threats, or fix bugs. At that point, PGE would have to perform this work in-house at significant cost and risk.

     For example, PGE's financial system is 26 years old, the vendor is no longer making enhancements, and we need a system that can accommodate the International Financial Reporting Standards (IFRS) that are currently expected to be required by 2012 (i.e., 2014 but with two prior years of detail). PGE can incur additional costs to upgrade these legacy systems with the new requirements but this means we would not have ongoing vendor support as the technology and user requirements continue to change.
   - Operational efficiencies through process improvement – inefficient and redundant processes will be identified and improved, thereby increasing operational efficiency. Examples of benefits include:
     - Elimination of manual processes, reduction of redundant work, improved workflow, and more efficient reconciliation. In addition, PGE expects to: 1) have a more effective capital and O&M budgeting process, 2) have enhanced ability to forecast multiple scenarios and analyze data, 3) capture PGE's financial commitments and expected cash flows automatically, and 4) strengthen our internal controls by automating current manual controls.
     - Optimization of resources across maintenance, construction, and inspection groups. Currently, resource assignments are assembled manually and dispatched by individual workgroups, limiting the ability for workforce leveling or resource optimization across the organization. A fully integrated work and asset management system, built on standard

business processes, will reduce the amount of manual reconciliation and handling required for scheduling and dispatch. In addition, it will enable PGE to compare and contrast similar work activities by crew or region.

- Improvements in customer service – Customer information can be connected to: 1) the assets associated with providing electric service (i.e., transformers, poles, wires, meters, etc), and 2) the PGE resources responsible for building, maintaining, and repairing those assets. For example, an Asset Management system that is fully integrated with GIS and Outage Management applications, in conjunction with our Smart Meters, can create a foundation for future projects to allow customers to access their service information and the status of restoration efforts in real-time.

  Currently, there is no intelligent connectivity model for PGE's distribution system and outages are determined via "roll ups" of circuit maps. This results in additional time spent diagnosing the outage, incomplete knowledge of the outage boundaries and affected customers, and less than optimal crew dispatching for restoration efforts.
- Improved asset utilization – Currently, PGE does not have the means for a consistent asset management strategy or process, across organizations and individual work groups, to determine how best to utilize our assets. Because departments independently conduct narrowly scoped work on the same assets, without a holistic view of the work required, some re-work and revisits to any given asset may occur. With up-to-date technologies and standardized processes PGE can benefit from "just in time" inventory and we will have more accurate information to identify when critical assets need replacing rather than use a time-based replacement strategy.
- Smart grid connectivity – With PGE's current fragmented systems, smart grid data will not be available across applications and cannot be fully utilized. Consequently, PGE's current technology will become a bottleneck to realizing future smart grid potential. By implementing the 2020 Vision program, with process improvement and standardization, PGE can use real-time, smart grid information to optimize PGE's power delivery system (e.g., transformers and other assets) and realize more dependable and more rapid outage identification.
- Knowledge transfer – Much of PGE's knowledge of operational practices resides within the individuals currently performing the work. Over the next five to ten years, we anticipate that a significant percentage of our IT workforce will retire. The effort required to migrate work processes from legacy applications to new systems offers a unique opportunity to address how we capture process knowledge and train new employees, so that as much as possible, our historical contexts, policies, and ways of working will not be lost in the labor transition.
- Time to complete – Because the systems will take up to seven years to fully implement and given the needs/benefits identified above, PGE believes it is inappropriate to delay the program beyond the current schedule.

- Based on the last four years of historical costs, PGE estimates that without implementing the proposed projects, the cost of maintaining and upgrading PGE's existing systems over the next five years will be approximately $44 million. This would maintain current functionality and business processes and provide little or no additional business value, while at the same time would:
  - Leave PGE unable to respond to increasing demands for real-time information, changing customer needs, and increasing regulatory requirements;
  - Impair PGE's ability to pursue business process improvement efficiencies;
  - Require continued significant investment in IT integrations of disparate systems in an attempt to provide the seamless flow of data across applications, such as the data required for and provided by the Smart Grid;
  - Put PGE at risk of losing valuable knowledge currently embodied in long-time employees' understanding of how to work across disparate information systems;
  - Weaken PGE's ability to attract and retain new talent to replace retiring workers;
  - Inhibit PGE's ability to leverage the capabilities of Smart Grid technologies currently being implemented; and
  - Be analogous to paving cow-paths rather than investing in a modern freeway system.

ii. Information Security provides significant benefits but primarily in the form of avoiding the increasing risk of sophisticated data breaches, data loss, or compromised operations by hackers who could exploit vulnerabilities in PGE's cyber and critical infrastructure assets. We would also face financial penalties due to non-compliance with legal and regulatory requirements. In short, PGE cannot afford to defer this work. The study used to identify the security measures and initiatives from which PGE developed its Information Security Roadmap was provided in confidential work papers to PGE Exhibit 500, UE 319 (see "Risk-based Prioritizations and Updated Security Roadmap").

iii. Customer Engagement Transformation (CET) program became the last portion of 2020 Vision and was discussed separately in PGE Exhibit 900, UE 262; PGE Exhibit 1000, UE 283; PGE Exhibit 900, UE 294; and PGE Exhibit 900, UE 319. Benefits from CET include:

- Provide several enhancements that are responsive to customer needs, including the ability for customers to:
  - Make one-time check payments over the phone; currently customers are redirected to the IVR system or the PGE website to make the payment.
  - Enroll in Auto Pay or update bank account information over the phone.
  - Choose the specific date their bill will be due, instead of the bill cycle (date range), helping customers better plan and manage their cash flow.

  - Enroll in the Preferred Due Date program with fewer restrictions making it more accessible to customers who could benefit the most.
  - Keep their new account number permanently (when new systems are implemented), even when they move to a different address within PGE's service territory.
- Support more varied pricing options compared to what is available with our current system.
- Replace systems that have become technically and functionally obsolete, are not suited for emerging smart grid requirements and changing customer expectations, and must be replaced if PGE is to remain responsive to customers' needs, expectations, and preferences.

iv. Transmission and Distribution (T&D) strategic capital improvements relate to customer-driven capital work and efforts to improve the T&D system to: 1) replace or upgrade equipment nearing the end of its life; 2) redesign portions of the system to improve reliability; and 3) better prepare for earthquakes, cyber-attacks, and other threats. This effort was guided by a third-party assessor, Black & Veatch (B&V) that PGE hired to review our T&D asset management practices and capabilities. B&V's assessment of T&D – a Publicly Available Specification 55 (PAS-55) – is provided in confidential work papers to PGE Exhibit 800, UE 319. Based on this assessment, PGE created the Strategic Asset Management department (SAM) to develop an annual T&D risk assessment and associated portfolio of recommended risk reduction projects. The objective of SAM's methodology is to consider the negative impacts of service failure on:

- System reliability;
- Public and worker safety;
- Environmental stewardship; and
- Efficient expenditure of funds.

SAM identifies system improvements that demonstrate <u>maximum value to customers in terms of risk reduction</u>. The types of projects include:

- Asset replacement by proactively replacing infrastructure that is operating beyond its life and thus creating reliability, safety, environmental, and cost threats for customers;
- System reconfiguration by shifting loads in the system or reconfiguring system designs to better manage load and can reduce the impacts of service failures on customers should they occur; and
- Grid modernization by installing new types of advanced technologies that can help PGE increase reliability and meet new customer demand (e.g., PGE's Smart Grid initiatives).

UE 319

Attachment 558-A

Provided in Electronic Format only

FTE Data Provided in UE 319 Testimony, Exhibits, and Responses to Data Requests

UE 319

Attachment 558-B

Provided in Electronic Format only

UE 262; PGE Exhibit 201

UE 319

Attachment 558-C

Provided in Electronic Format only

UE 283; PGE Exhibit 707

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman, Ph.D.
Marco Espinoza

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE. I am responsible for the development of PGE's revenue requirement forecast and other regulatory analyses.

My name is Marco Espinoza. I am a Senior Financial Analyst in Regulatory Affairs.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's 2019 revenue requirement for base business of $1,884.6 million.

Q. What increase in revenue requirement does PGE request beginning January 1, 2019?

A. PGE requests a base business increase of $85.9 million or 4.8% effective January 1, 2019. This increase is relative to the revenues we expect based on 2018 prices approved by Public Utility Commission of Oregon (Commission) Order No. 17-511 in Docket No. UE 319 (UE 319). This revenue requirement will allow PGE an opportunity to earn a 7.31% rate of return that includes a 9.50% return on average common equity (ROE) in 2019.[1] PGE Exhibit 201, columns 1 through 3, summarizes the development of PGE's 2019 revenue requirement for base business. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss our unbundled revenue requirement in Section IX.

Q. What mitigating actions did PGE take to help limit the size of the requested increase in this filing?

[1] As discussed in PGE Exhibit 1000, PGE proposes a 50/50 capital structure between debt and equity.

A. As described in PGE Exhibit 100, to reduce the price impact on customers, we adjusted PGE's revenue requirement by:

1. Reducing our request related to incentive compensation costs;
2. Removing 50% of certain layers of directors and officers insurance; and
3. Requesting a return on equity at the lower portion of the range supported by PGE's expert witness.

A. PGE Result if No Price Increase is Authorized

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2019?

A. Without a price increase, we would expect PGE's ROE to be approximately 7.0% in 2019, significantly lower than the authorized ROE of 9.50%.

B. Structure of the Case

Q. Please summarize PGE's 2019 revenue requirement.

A. Table 1 below, summarizes PGE's 2019 revenue requirement by major category and provides a comparison to the results of UE 319. We also list the PGE testimony that addresses each specific cost category.

Table 1
Revenue Requirement Summary
($millions)

Rev Req Category	UE 319 Approved	2019 Forecast	Exhibit	No.
Sales to Consumers	$ 1,813.2	$ 1,884.6	Rev Req	200
Other Revenue	26.8	25.3	Rev Req	200
NVPC	336.0	375.3	Power Costs	300
Production O&M	160.0	165.7	Production	700
Transmission O&M	14.3	15.8	T&D	800
Distribution O&M	120.2	136.2	T&D	800
Customer Service	80.7	85.2	Customer Svc.	900
A&G	159.1	180.8	Corp. Support	500
Depr. & Amort.	360.1	372.5	Rev Req	200
Other Taxes	125.4	138.5	Rev Req	200
Income Taxes	153.1	84.8	Rev Req	200
Operating Income*	**$ 331.2**	**$ 355.1**		
Return on Equity	9.5%	9.5%	Return on Equity	1000

** May not sum due to rounding*

Q. Please describe Operating Income as used in Table 1 above.

A. Operating Income consists of a return to the providers of capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibit 1000.

Q. How did you develop the 2019 revenue requirement?

A. We developed the revenue requirement based on PGE's 2018 budgets, which were originally based on UE 319 prices as authorized by Commission Order No. 17-511. The 2018 budgets were escalated for inflation to 2019 and adjusted for known and measureable changes.

Q. How did you escalate the 2018 budget to 2019 test year?

A. We applied the following escalation rates to the 2018 budget:

- 3.68% average rate for all labor (at applicable effective dates[2]);
- 2.72% for outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1;
- 1.71% for direct materials (CE 2101 and 2110), effective January 1; and
- 2.54% for employee business expense (CE 2400 and 2701), effective January 1.

Q. What are the sources of these escalation rates?

A. For outside services, direct materials and employee business expense, we use escalation rates from the *Global Insights*, Long-term Forecast dated August 2017. Wage escalation is based on the forecast of compensation costs as described in PGE Exhibit 400.

[2] March 1 for bargaining employees and March 15 for non-bargaining employees, resulting in an annualized average rate of 2.95%.

Q. What comparison with the 2019 test year costs does PGE make in the testimonies generally?

A. We compare our forecast of 2019 test year costs to 2017 actuals. We do this because 2017 represents PGE's most recent full year with actual results. The changes between 2017 and 2019 in this filing will be analyzed on an average annual basis.

Q. Did you adjust PGE's 2019 revenue requirement to reflect previous pricing decisions and other regulatory policies?

A. Yes. We made several regulatory adjustments, listed in Table 2 below.

Table 2
Regulatory Adjustments
($millions)

Category	O&M	Rate Base
Retail Services	$ (0.2)	$(0.9)
Charitable Contributions	(2.1)	
State & Federal Lobbying	(0.9)	
MDCP	(4.8)	
SERP	(1.4)	
Image Advertising	(0.7)	
Total Adjustments	**$ (10.1)**	**$(0.9)**

Q. Please explain these regulatory adjustments.

A. The following is a brief summary of the adjustments:

- Retail services: removed the revenue requirement related to amounts allocated to PGE's retail operations;
- Charitable contributions: excluded the entire $2.1 million from cost of service;
- State and federal lobbying: excluded the entire $0.9 million from cost of service;
- Managers' Deferred Compensation Plan (MDCP): removed the entire $4.8 million from cost of service;

- Supplemental Executive Retirement Plan (SERP): removed the entire $1.4 million from cost of service; and
- Corporate image advertising: removed the entire $0.7 million from cost of service.

II. Other Revenue

Q. What is PGE's 2019 forecast of Other Revenue?

A. PGE forecasts 2019 Other Revenue of $25.3 million. This compares to actual 2017 Other Revenue of $25.4 million.

Q. What are the sources of Other Revenue?

A. The primary sources of Other Revenue are rent of electric property, transmission revenue, joint-pole revenue, steam sales revenue, and ancillary service revenue. PGE Exhibit 202 provides additional detail on the sources and amounts of Other Revenue.

Q. Did you make any adjustments related to Other Revenue for the 2019 test year?

A. Yes. We adjusted the 2019 forecast of transmission revenues received from Electricity Service Suppliers (ESSs). The adjusted amount reflects PGE's current Open Access Transmission Tariff rate and the forecasted 2019 direct access load. We also added approximately $0.6 million for fees collected for Green Power Administration costs to avoid double collecting these costs. In addition, we added approximately $0.2 million for income associated with PGE's affiliate, Salmon Springs Hospitality Group, in accordance with Commission Order No. 06-250. Finally, we reduced Other Revenue by $1.2 million to reflect the reduction in PGE's rental rate for wireless attachments to PGE poles.

III. Depreciation

Q. What is the basis for the 2019 test year book depreciation expense?

A. Normalization rules in the Internal Revenue Code, Section 168(i)(9) require consistency in the calculation of four items for ratemaking purposes. Two of the four items are tax expense and book depreciation expense. The other two items are in rate base: accumulated book depreciation and accumulated deferred income taxes. Because PGE established its rate base as of December 31, 2018, we used 2018 depreciation in the calculation of all four items.

Q. Does 2018 depreciation accurately reflect the 2019 expense?

A. By itself, no. Because 2018 depreciation will only reflect partial year depreciation for all 2018 plant closings, 2018 depreciation will be less than 2019 depreciation, which will reflect a full year of depreciation for those same assets (assuming no additional plant closings[3] in 2019). In order to adjust for this effect, PGE annualized the 2018 depreciation expense for 2018 plant closings and then reduced that amount to account for the fact that PGE's declining balance method results in a 2019 depreciation expense that would not be as high as that calculated with the full annualization effect. The net result is that the test year depreciation is based on 2018 expense (to meet IRS normalization requirements), but has an adjusted annualization so that PGE does not under-collect or over-collect depreciation expense relative to expected 2019 depreciation expense. As noted above, the expected 2019 depreciation expense does not reflect any 2019 closings. For simplicity, we refer to the test year depreciation as 2019 depreciation expense.

Q. What is PGE's estimate for 2019 depreciation expense?

[3] "Plant closings" refers to the accounting entries that move costs from Construction Work in Progress to Plant in Service when the assets become operational.

A. We estimate $305.5 million in depreciation expense for 2019. PGE Exhibit 203 summarizes the 2019 depreciation expense by plant type and provides a comparison to 2017 actuals.

Q. Is PGE proposing a new depreciation study as part of this rate case?

A. No. PGE's most recent depreciation study was approved in Docket No. UM 1809 through Commission Order No. 17-365. PGE implemented the new depreciation rates effective January 1, 2018.

Q. How does PGE's 2019 depreciation expense forecast compare to 2017 actuals?

A. After adjustments, total forecasted depreciation for 2019 reflects a $6.1 million increase over 2017 actuals.

Q. What are the primary drivers for the increase?

A. The primary drivers of the increase in depreciation expense are:

- $2.1 million in wind, solar, and hydro generation resources;
- $2.0 million in transmission and distribution facilities;
- $2.7 million for general plant; partially offset by
- $0.7 million reduction in thermal plants.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life. Amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate. Because amortization is also subject to tax normalization principles, we calculated the 2019 test year amortization expense based on the adjusted annualized 2018 amortization similar to depreciation.

Q. Please summarize PGE's 2019 amortization expense.

A. PGE Exhibit 204 details the total 2019 amortization expense of $67.0 million, which we summarize in Table 3 below.

Table 3
Amortization
($millions)

Amortization Item:	**2017 Actuals**	**2019 Forecast**
Software Amortization 5-10 year	$ 37.6	$ 55.8
Other Intangible Amortization	8.6	8.7
Trojan Decommissioning	3.5	2.5
Total Amortization*	**$ 49.6**	**$ 67.0**

***** *May not sum due to rounding*

Q. Please explain the amortization of software included in PGE's 2019 amortization expense.

A. Total software amortization is approximately $55.8 million. This cost relates to capitalized software, which is typically amortized over a 5-year period, with the exception of larger software programs that are amortized over a 10-year period. Examples of the larger software programs are the Customer Engagement Transformation (CET) program[4] and 2020 Vision program (including the Finance and Supply Chain Replacement project, Maximo Mobile Scheduling, Outage Management System, Graphic Work Design, and Geographic Information System).

Q. Why is software amortization approximately $18 million higher in 2019 compared to 2017?

A. The increase is primarily due to: 1) software investment in the Customer Touchpoints project that is forecasted to close to Plant in Service during 2018; 2) additional 2018 software investment; and 3) software investment that closed to plant during 2017, resulting in partial year amortization in 2017, but full year amortization in 2018.

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous other intangible plant amortization. For hydro relicensing, this represents the recognition of annual costs associated with non-construction projects that have closed to Plant in Service. Generally, these costs are amortized over the life of the new license.

Q. Does PGE recommend any changes to the current $3.5 million Trojan Nuclear Decommissioning Trust (Trojan NDT) collection rate?

A. Yes. We performed an analysis of the annual accrual, updated for the latest Trojan NDT balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicated that a reduction in the collection rate is advisable. Based on the analysis and the considerable uncertainty still associated with the spent nuclear fuel at the Trojan site, PGE proposes a lower annual accrual rate of $2.5 million, which represents a

[4] PGE Exhibit 900 provides a detailed description of the CET program.

$1.0 million reduction to the current annual accrual. Our current Nuclear Regulatory Commission license for Trojan will expire in March 2019 and PGE is currently in the process of renewing it for an additional 40 years with an end date estimated to occur in 2059.

Q. What decommissioning activities are planned at Trojan in the future?

A. No further decommissioning work is planned until after the spent nuclear fuel has been removed from the site. The majority of the structures at the facility have already been demolished. PGE completed the decommissioning and demolition of the Trojan North and Trojan Training buildings in 2014.

V. Income Taxes, Taxes Other Than Income, and Fees

A. Income Taxes

Q. What is PGE's 2019 estimate of income taxes?

A. PGE's 2019 test year forecast for income tax expense is $84.8 million. This compares to the 2018 utility income tax expense of $153.1 million based on prices approved by Commission Order No. 17-511 in UE 319. PGE Exhibit 205 provides details on the test year calculations of income tax expense plus a comparison to previously authorized 2018 income tax assumptions. The decrease in 2019 test year income tax expense compared to the approved 2018 expense reflects the impact of the tax legislation[5] (Tax Plan) enacted on December 22, 2017, which included a provision that reduces corporate income tax rates. We discuss the tax legislation in more detail below.

Q. What methodology did you use to establish estimated income tax expense for the 2019 test year?

A. We use the "stand-alone" method to determine the test year income tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the income tax expense for the test year. The Commission has traditionally used this approach to determine the income tax expense in test year price development. Further, because PGE's operations are nearly 100% regulated utility activity, this method also conforms to ORS 757.269, which specifies how income taxes are treated for developing prices.

[5] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018. Public Law Number 115-97.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the federal government, the States of Oregon, Montana, and California, and to local government entities such as the City of Portland and Multnomah County.

Q. Please describe the specific impacts of the recent tax legislation.

A. The recent tax legislation that was enacted on December 22, 2017 includes provisions that directly and indirectly affect PGE's revenue requirement. The most important provision is the lowering of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. This has the immediate effect of reducing PGE's current and deferred income tax expense. Additional impacts on PGE's 2019 revenue requirement consist of:

- Reduction of PGE's accumulated deferred income tax (ADIT) liability;
- Elimination of the Domestic Production Activities Deduction;
- Adjustment of production tax credits (PTCs) in power costs due to the lower gross-up for taxes; and
- Inclusion of the excess ADIT reversal.

Q. Why does the ADIT balance decline?

A. In total, PGE's year-end 2018 ADIT declined by approximately $17.4 million. This is primarily due to a larger projected carryover of PGE's PTCs since the lower corporate tax rate results in a lower tax expense on which to utilize the credits.

Q. Please explain the elimination of the Domestic Production Activities Deduction.

A. One of the provisions of the Tax Plan was to repeal the Domestic Production Activities Deduction or "Production Deduction". This deduction had reduced PGE's federal taxable income by $9.0 million in prior rate case revenue requirements.

Q. Please elaborate on the inclusion of the excess ADIT reversal.

A. As noted above, the excess ADIT needs to be amortized over the average life of PGE's assets in accordance with IRS normalization requirements[6] (i.e., using the average rate assumption method – ARAM). As a result, PGE's calculated total income tax expense will be lower in the 2019 test year by approximately $7.0 million.

Q. Has PGE submitted any other filings in relation to the Tax Plan?

A. Yes. On December 29, 2017, PGE filed for deferred accounting treatment for the expected 2017 and 2018 net benefits associated with the provisions implemented through the Tax Plan. Because of the length and complexity of the legislation, PGE will continue to evaluate the Tax Plan's implications.

Q. What marginal tax rates have you incorporated into your 2019 test year revenue requirement?

A. The federal marginal tax rate is 21.0%, the State of Oregon marginal tax rate is 7.60%, the State of California marginal tax rate is 8.84%, and the State of Montana marginal tax rate is 6.75%. We also include the City of Portland marginal tax rate of 2.20%.

Q. What is PGE's state composite tax rate for this filing?

A. PGE's state and local composite tax rate is 7.788%. The rate is a function of the marginal state tax rates and the respective apportionment factors of taxable income to different state and local jurisdictions.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 27.151%, which is the sum of the federal marginal tax rate and the state and local composite tax rate, less the effect of their interaction

[6] P.L. 115-97, §1561(d)(1).

(i.e., local income taxes reduce state income taxes and state income taxes reduce federal income taxes), or:

21.00% + 7.7877% - ((21.00% * 7.7877%) - (7.600% - 0.0167%)) = 27.151%

Q. Did you exclude any tax rates from local jurisdictions from the calculation of the composite tax rate?

A. Yes. PGE collects Multnomah County Business income taxes through a supplemental tariff to comply with OAR 860-022-0045. As such, we do not include an estimate of the costs as part of our revenue requirement in this proceeding.

Q. Did you include state and federal tax credits in your estimate of income tax expense for 2019?

A. No. Consistent with the provisions of Oregon Senate Bill 1547, Section 18b, federal PTCs are now incorporated as part of PGE's net variable power costs. Additionally, all of PGE's state tax credits have been utilized and there are none currently forecasted for 2019.

B. Taxes Other than Income and Fees

Q. What is PGE's 2019 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $138.5 million for 2019. This compares to 2017 actual costs of $122.4 million. The primary cost changes from 2017 actuals to the 2019 test year are:

- Property Taxes: from $61.4 million to $71.6 million;
- Franchise Fees: from $43.0 million to $47.8 million; and
- Payroll Taxes: from $15.4 million to $16.6 million.

1. Property Taxes

Q. Please describe PGE's obligation to pay property taxes.

A. PGE owns property in three states: Oregon, Montana (Colstrip plant and related transmission), and Washington (Tucannon River Wind Farm and KB Pipeline for gas used at the Port Westward and Beaver plants). As a result, PGE is obligated to pay property taxes in each of these jurisdictions.

Q. How do these jurisdictions assess property taxes on PGE?

A. Rather than each individual county assessing property tax, Oregon, Montana, and Washington "centrally assess" PGE's property using a unit approach. This unit approach is required by state statutes because the properties are considered a single economic unit and system assets are thoroughly integrated in operation and construction. For example, a piece of wire cannot be valued without looking at its relationship to the entire unitary system. Each state uses a combination of three approaches to determine value: 1) cost, 2) income, and 3) comparable sales. The result of each approach is considered and weighted by each respective state assessor in determining a correlated system value. The goal of this valuation process is to assess PGE's operating system as closely as possible to its real market value on January 1 of each year.

Q. Is PGE including property tax savings incentives related to major construction projects?

A. Yes. Similar to prior years, PGE has included tax savings related to Strategic Investment Program (SIP) property tax abatement agreements, which significantly reduces taxes for a 15-year period beginning in 2008 for Biglow Canyon, Port Westward II, and Carty.

Q. What is PGE's forecast for 2019 property tax expense?

A. PGE has forecast approximately $71.6 million of 2019 property taxes compared to 2017 actuals of $61.4 million.

Q. Why are property taxes increasing from 2017 to the 2019 test year?

A. $5.4 million of the increase is due to an increase in plant assets and $1.3 million is due to an increase in the Oregon property tax rate. Additionally, a full year of the Carty SIP is included in 2019, totaling $1.3 million, versus a half-year that was payable in 2017. Approximately $2.2 million of the increase is due to additional CWIP[7] balances that will be assessed property tax expense, $0.5 million is due to higher Montana levy rates for Colstrip, and $0.3 million is due to a higher tax assessment for Tucannon.

2. Franchise Fees

Q. Why have franchise fees increased from 2017 to the 2019 test year?

A. PGE updated the franchise fee rate to reflect the three-year average of 2015-2017 actuals. Although the franchise fee rate drops slightly from 2.545% in 2018 (UE 319) to 2.538% in 2019, overall, franchise fees increase because PGE's requested revenue requirement increases.

3. Payroll Taxes

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 8.6% payroll tax rate to total wages and salaries. We allocate a portion of payroll tax cost to capital consistent with the allocation of overall capitalized wages and salaries.

Q. Why have payroll taxes increased from 2017 to the 2019 test year?

[7] Construction work in progress.

A. Payroll taxes increase as wages and salaries grow between these years as described in PGE Exhibit 400.

VI. Rate Base

Q. What is PGE's 2019 rate base and what does it include?

A. PGE has established its rate base balances as of year-end 2018, and forecasts the total balance to be approximately $4,857.2 million. PGE Exhibit 207 provides the details of the 2018 rate base, which includes PGE's investment in Plant in Service, net of Accumulated Depreciation, and ADIT.[8] In addition, the rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2018 rate base compare to amounts approved in UE 319?

A. PGE Exhibit 208 shows that the rate base approved in UE 319 is $4,505.4 million and that PGE's 2018 rate base reflects an increase of $351.8 million. The increase is primarily attributable to the growth in distribution plant as discussed in PGE Exhibit 800, as well as the Customer Touchpoints project as discussed in PGE Exhibit 900.

Q. What is the Working Cash total added to rate base in this filing?

A. PGE has updated its lead/lag study to determine the Working Cash factor for use in calculating PGE's Working Cash total in rate base. This analysis results in the Working Cash factor increasing from 3.628% in 2018 (UE 319) to 4.063% in 2019. Applying the 4.063% Working Cash factor to total forecasted operating expenses in 2019 of $1,554.8 million produces the Working Cash total in rate base of approximately $63.2 million. This amount is shown in PGE Exhibit 201.

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[8] ADIT is also calculated based on year-end 2018 amounts, consistent with IRS Normalization principles.

VII. Carty Update

Q. Please summarize the ratemaking relief PGE sought for Carty in Docket No. UE 294 (UE 294).

A. In UE 294, PGE requested that prices recovering Carty's net revenue requirement become effective shortly after a PGE officer provided an attestation that Carty was placed in service.

Q. Did Commission Staff analyze the prudence of PGE's actions related to Carty?

A. Yes. Staff analyzed the prudence of PGE's actions related to Carty from two perspectives. First, Staff analyzed the consistency of Carty with previous integrated resource plans and request for proposals. Second, Staff analyzed the prudence of Carty as of the date when PGE decided to proceed with the project.[9]

Q. What was the outcome of UE 294, with respect to Carty?

A. On November 3, 2015, the Commission issued Order No. 15-356 approving settlements reached in UE 294. With respect to Carty, the approved settlements stipulate PGE's decision to construct Carty was prudent. The approved settlements also identify the conditions for which Carty's prudently incurred costs and benefits would be included in customer prices when Carty begins providing service to customers. The conditions include:[10]

> i. For determining rates in this docket only, the gross plant for Carty, including the Grassland Switchyard, will be $514 million… If Carty capital costs are higher than the designated amount, PGE may not recover those costs through the Carty tariff rider. However, PGE will not be bound to the original $514 million estimate in subsequent rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.

[9] See UE 294 Staff Exhibit 1700, page 6.
[10] Commission Order No. 15-356, Appendix A, pages 4 and 5.

ii. PGE will file an attestation by an officer when the Carty plant is placed in service.

iii. If the Carty Generating Station is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request seeking the inclusion of the Carty costs in rates, inclusive of Grassland Switchyard.

Q. Did PGE place Carty into service by July 31, 2016?

A. Yes. PGE placed Carty into service on July 29, 2016 and an officer attestation was submitted to the Commission.

Q. What are the overall construction costs to build the Carty facility?

A. As of September 30, 2017, PGE has capitalized $637 million to electric utility plant, excluding certain lien claims totaling $8 million that PGE is challenging.

Q. Does this rate case include the additional construction costs associated with Carty?

A. No. PGE included only the original cost estimate of $514 million.

Q. Is PGE continuing to diligently pursue payment from Liberty Mutual and Zurich American Insurance Company pursuant to a performance bond as described in PGE's SEC financial statement disclosures?

A. Yes. For a more complete update on the status of these legal matters, see PGE's 2017, Form 10-K (Part II, Item 8, Note 17).

VIII. Customer Engagement Transformation (CET)

Q. Please provide an update on PGE's CET program.

A. PGE continues to work toward the completion of CET, which has been a multi-year program consisting of 24 projects and culminating in 2018 with the replacement of two legacy customer systems: Customer Information System and Meter Data Management System. We refer to the systems replacement project as Customer Touchpoints.

Q. Are you including the costs for Customer Touchpoints in your current request?

A. Yes. PGE is including the 2018 Customer Touchpoints project as part of this revenue requirement. CET capital costs and a detailed update of Customer Touchpoints are provided in PGE Exhibit 900.

IX. Unbundling

Q. Have you unbundled the 2019 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 210 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-038-0200, into the required functional areas or revenue requirement categories. Table 4 below summarizes the base unbundled revenue requirement for 2019.

Table 4
Unbundled Revenue Requirement
($millions)

Production	$ 1,061.4
Transmission	33.1
Distribution	638.7
Ancillary	4.8
Metering	10.8
Billing	70.9
Other Consumer Services	64.8
Total*	**$ 1,884.6**

** May not sum due to rounding*

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 201 columns 1 through 3.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on rate base – to calculate the revenue requirement for each unbundled service in accordance with OAR 860-038-0200(9)(d).

Q. How did you unbundle PGE's 2019 expenses and Other Revenue?

A. We unbundled expenses and Other Revenue by analyzing each account within those categories. First, we determined which accounts could be directly assigned to one of the functional categories listed in Table 4 above. Second, we evaluated those accounts that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and Other Revenue accounts assigned or allocated?

A. The majority of accounts have a direct relationship with a single functional area and we assigned these accounts based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated costs is administrative and general (A&G), which we allocated to the functional areas based on labor dollars for those areas. Other costs, such as property taxes, and payroll taxes, relate to factors such as net plant or labor. We allocated these costs based on the respective share of those factors per functional area in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective plant accounts" – see OAR 860-038-0200(9)(c)(A).

Q. Did you allocate any expense or Other Revenue to retail or non-utility?

A. Yes, for retail and no for non-utility. First, we allocate costs to retail activities based on assets allocated to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these accounts already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., Facilities, Information Technology, and Print/Mail Services) based on that labor. Therefore, unbundling A&G (or other support costs) to non-utility accounts would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two categories of rate base that we evaluated for unbundling: 1) Plant in Service with associated Depreciation Reserve, and Accumulated Deferred Income Taxes; and 2) other rate base. For Plant in Service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro generating plants; transmission towers and conductors; distribution poles, conductors, substations, transformers, and service drops). Some general and intangible plant was directly assigned, but the majority of these categories consist of many smaller assets without a clear functional attribute so we allocated them based on labor.

Q. How did you unbundle other rate base?

A. We assigned or allocated other rate base using the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated other rate base on an account-by-account basis and directly assigned where applicable (e.g., fuel inventories are assigned to Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Did you assign franchise fees to the distribution function?

A. Yes. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), PGE assigned franchise fees directly to the distribution function. We also assigned write-offs for uncollectibles directly to the distribution function.

X. Qualifications

Q. Dr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University. I received a Master of Arts degree in Economics and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

Q. Mr. Espinoza, please state your educational background.

A. I received a Bachelor of Science degree in Economics from Portland State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2006. I have been employed at PGE since 2000, working in various departments including Risk Management, Corporate Planning, and Financial Forecasting. I joined the Rates and Regulatory Affairs department in 2017.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	2019 Results of Operations Summary
202	Summary of Other Revenue Sources
203	Summary of Depreciation Expense by Plant Type
204	Summary of Amortization Expense
205	Summary of Income Taxes
206	Summary of Taxes Other Than Income
207	Summary of Rate Base
208	Rate Base Comparison
209	Production Tax Credits
210	Unbundled Results of Operations Summary

PGE Exhibit 201
2019 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business		4.78%
	2019 Results at 2018 Base Rates	Change for Reasonable Return	2019 Results After Change for Reasonable Return
	(1)	(2)	(3)
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,798,713	85,908	1,884,622
Sales for Resale	-	-	-
Other Operating Revenues	25,327	-	25,327
Total Operating Revenues	1,824,041	85,908	1,909,949
Operation & Maintenance			
Net Variable Power Cost	375,309	-	375,309
Operations O&M	317,758	-	317,758
Support O&M	265,341	571	265,911
Total Operation & Maintenance	958,407	571	958,978
Depreciation & Amortization	372,496	-	372,496
Other Taxes / Franchise Fee	136,361	2,180	138,541
Income Taxes	62,226	22,571	84,797
Total Oper. Expenses & Taxes	1,529,491	25,322	1,554,812
Utility Operating Income	294,550	60,586	355,137
Rate of Return	6.065%		7.312%
Return on Equity	7.008%		9.500%
* 2018 Rates per approved UE 319			
Rate Base			
Plant in Service	10,221,818	-	10,221,818
Accumulated Depreciation	(4,761,822)	-	(4,761,822)
Accumulated Def. Income Taxes	(679,665)	-	(679,665)
Accumulated Def. Inv. Tax Credit	-	-	-
Net Utility Plant	4,780,331	-	4,780,331
Misc Deferred Debits	9,294	-	9,294
Operating Materials & Fuel	78,945	-	78,945
Misc. Deferred Credits	(74,554)	-	(74,554)
Working Cash	62,143	1,029	63,172
Total Rate Base	4,856,160	1,029	4,857,189
Income Tax Calculations			
Book Revenues	1,824,041	85,908	1,909,949
Book Expenses	1,467,265	2,751	1,470,015
Interest Rate Base @ Weighted Cost of Debt	124,394	26	124,420
Production Deduction	-	-	-
Permanent Sch M Differences	(22,619)	-	(22,619)
Temporary Sch M Differences	63,378	-	63,378
State Taxable Income	191,623	83,131	274,755
State Income Tax	14,921	6,473	21,394
Federal Taxable Income	176,703	76,658	253,361
Fed Income Tax	37,108	16,098	53,206
Deferred Taxes	17,208	-	17,208
Excess ADIT Reversal (ARAM)	(7,010)	-	(7,010)
Federal Tax Credits	-	-	-
Total Income Tax	62,226	22,571	84,797

PGE Exhibit 201
General Rate Case - 2019 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	Amount	Share	Cost	Weighted
Common Equity	N/A	50.00%	9.500%	4.750%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.123%	2.562%
Total	N/A	100.00%		7.312%

Revenue Sensitive Costs:	
Revenues	100.0000%
OPUC Fees	0.3211%
Franchise Fees	2.5376%
O&M Uncollectibles	0.3431%
State Taxable Income	96.7982%
State and Local Tax @ 7.7865%	7.5372%
Federal Taxable Inc.	89.2610%
Federal Tax @ 21.000%	18.7448%
Total Income Taxes	26.2820%
Total Rev. Sensitive Costs	29.4838%
Utility Operating Income	70.5162%
Net To Gross Factor	1.418114
RSC Gross-Up Factor	1.0331

State and Local Income Tax:

	Appor	Rate	Weighted
Portland	0.76%	2.20%	0.015%
Montana	2.86%	6.75%	0.193%
California	2.06%	8.84%	0.182%
Oregon	97.32%	7.60%	7.396%
State and Local Tax Rate			7.786%

Less Local Benefit to Oregon:	
Oregon Rate	7.6000%
Local Rate	-0.0167%
Oregon Benefit of Local Tax deduction	-0.0013%

Composite Tax Rate:		27.1513%
Check:	Fed Tax	21.0000%
	State Tax	7.7865%
	Tax Shield	-1.6352%
	Composite	27.1513%
Working Cash Factor		4.063%

PGE Exhibit 202
Other Revenue Detail
2015 - 2019 Test Year

Account	Description	2015 Actuals	2016 Actuals	2017 Actuals	2018 Budget	2019 Test Year
4470003	SalesfrResale-IntertiePGEtoPGE	(4,816,292)	(5,936,823)	(6,256,410)	(5,934,000)	(5,934,000)
4500001	Forefeited Discounts	(3,019,107)	(2,994,617)	(3,415,327)	(3,900,000)	(3,900,000)
4510001	Miscellaneous Service Revenues	(1,796,073)	(1,852,377)	(1,830,779)	(1,908,952)	(2,465,491)
4530001	Sales of Water & Water Power	22,164	24,166	26,668	-	-
4540001	Rent From Electric Property	(1,043,393)	(1,025,319)	(1,206,299)	(1,312,908)	(1,313,831)
4540002	RentFrElecProperty-Joint Pole	(6,564,797)	(7,679,162)	(6,444,068)	(6,504,350)	(5,300,350)
4560001	Other Electric Revenues	(3,487,297)	(3,648,451)	(3,825,497)	(3,466,954)	(3,468,351)
4560002	OthElecRev-RegulatoryDeferRev	323,401	517,749	1,809,924	1,405,570	1,283,381
4560003	OthElecRev-FishWildlifeRecrOps	(19,493)	(12,386)	(11,234)	-	(16,297)
4560004	OthElecRev-SSHG	(239,360)	(69,475)	(90,983)	(120,301)	(215,315)
4560005	OthElecRev-Utility Non-Kwh	(2,657)	(2,478)	(5,664)	-	-
4560012	OthElecRev-Steam Sales	(2,555,480)	(1,480,085)	(1,892,218)	(1,684,211)	(1,684,211)
4561001	TransRevOthers-Non-Intertie	(2,971,892)	(2,899,444)	(3,557,592)	(3,474,800)	(3,202,930)
4561002	TransRevOthers-Intertie	(5,285,337)	(5,080,702)	(4,953,843)	(5,044,000)	(5,044,000)
5660002	TransOp-MiscExp-IntertieWhePGE	4,816,292	5,936,823	6,256,410	5,934,000	5,934,000
Total		(26,639,321)	(26,202,580)	(25,396,912)	(26,010,906)	(25,327,395)

PGE Exhibit 203
Depreciation Detail ($000s)
2015 - 2019 Test Year

Property Group	(1) 2015 Actuals	(2) 2016 Actuals	(3) 2017 Actuals	(4) 2018 Budget	(5) 2018 Forecast used for 2019 Test Year
Boardman	29,642	30,023	28,627	28,711	29,209
Colstrip	5,308	5,161	10,022	9,546	9,732
Beaver	4,644	5,573	6,255	7,460	7,136
Biglow Canyon	33,490	32,095	30,912	32,830	31,268
Carty		6,696	13,883	13,609	12,740
Coyote Springs	5,136	4,919	4,831	4,616	4,891
DSG	332	340	354	344	391
Port Westward	8,647	8,668	8,506	8,467	7,974
Port Westward 2	8,160	8,042	7,654	7,660	7,511
Solar	42	79	192	358	165
Tucannon	17,316	16,761	16,232	15,675	15,284
Hydro	15,806	18,319	18,964	20,995	21,696
Transmission	9,078	10,025	12,616	12,710	12,055
Distribution	97,611	101,051	106,316	104,308	108,842
General Plant	33,915	35,430	38,248	38,884	40,939
Total	**269,127**	**283,182**	**303,612**	**306,173**	**309,834**
Remove Boardman Decommissioning	(5,877)	(5,877)	(4,225)	(4,225)	(4,225)
Retail Adjustment					(78)
Adjusted Total	**263,250**	**277,305**	**299,387**	**301,948**	**305,531**

Notes:

(1) 2015 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 15% ownership of non-coal handling assets, bringing PGE total share to 80%.
2015 depreciation excludes coal car depreciation of $261 and vehicle depreciation of $3,516 or $3,637

(2) 2016 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 10% ownership and retention program, bringing PGE total share to 90%.
2016 depreciation excludes coal car depreciation of $318 and vehicle depreciation of $4,781.
2016 Sunway becomes part of base business

(3) 2017 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2017 depreciation excludes coal car depreciation of $249 and vehicle depreciation (including helicopter) of $4,630.

(4) 2018 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2018 forecasted depreciation excludes coal car depreciation of $266 and vehicle depreciation (including helicopter) of $4,187.

(5) 2019 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2019 forecasted depreciation excludes coal car depreciation of $65 and vehicle depreciation (including helicopter) of $4,770.

PGE Exhibit 204
Amortization Detail
2015 - 2019 Test Year
($000)

Item	FERC Account	AWO	(1) 2015 Actuals	(2) 2016 Actuals	(3) 2017 Actuals	(4) 2018 Budget	(5) 2018 Forecast used for 2019 Test Year
Software Amortization (Intangible)	404.0		30,053	35,668	37,560	47,000	55,790
Other Intangible Plant (Includes Hydro Relicensing)	404.0		8,312	8,430	8,574	9,294	8,732
Trojan Decommissioning	407.0	7000000045	3,500	3,500	3,500	3,500	2,500
Trojan Spent fuel Settlement	407.0	3000000786	(16,800)	(16,340)	(18,982)	0	0
Independant Evaluator Deferral	407.3		547	35	0	0	0
Colstrip Common FERC Adjustment	407.3	7000000107	322	322	107	107	0
Schedule 110 EE Asset Balancing Acccount	407.3	7000000124	902	884	942	942	0
AMI Project Office Costs	407.3		0	0	0	0	0
Fit Pilot Program	407.3	7000002001	6,248	7,975	7,867	7,740	0
Regulatory Deferral Amortz	407.3	7000010741	18,959	155	0	0	0
Residual Balance	407.3		0	0	0	0	0
Regulatory Deferral (capital Deferral)	407.4	7000010741	0	0	0	0	0
2011 Local 408/MCBIT Deferral	407.4	3000000135	168	515	220	(200)	0
Int Income PES Note	407.4	7000000319	0	0	0	0	0
ISFSI Tax Credits-Used	407.4	7000000324	(5,290)	(300)	0	0	0
SunWay 3	407.4	7000000727	(45)	(45)	(45)	0	0
			46,875	40,798	39,743	68,383	67,022
Allocated to retail							(57)
Total Amortization			**46,875**	**40,798**	**39,743**	**68,383**	**66,965**

PGE Exhibit 205
Income Tax Summary
(000s)

Income Tax Expense	UE 319 2018 Test Year	2019 Test Year
Book Revenues	1,840,038	1,909,949
Book Expenses (including Depreciation)	1,355,693	1,470,015
Interest Deduction	117,207	124,420
Book Taxable Income	367,138	315,514
Production Deduction	9,000	-
Permanent Sch. M	(24,268)	(22,619)
Temporary Sch. M	45,835	63,378
Taxable Income	336,571	274,755
Current State Taxes	26,202	21,394
State Tax Credits	-	-
Net State Income Tax	26,202	21,394
Federal Taxable Income	310,369	253,361
Current Federal Taxes	108,629	53,206
Federal Tax Credits	-	-
ITC Amortization	-	(7,010)
Deferred Taxes	18,301	17,208
Total Income Tax	153,133	84,797
Effective Tax Rate	41.71%	26.88%
Change in Taxes		(68,335)
Analysis of Tax Change:		
Effective Tax Rate Change		-14.83%
Book Taxable Income (UE 294)		367,138
Decrease in Taxes Due to Lower Effective Rate		(54,461)
Change in Book Taxable Income (2019 vs UE 319)		(51,624)
2019 Effective Tax Rate		26.88%
Decrease in Taxes Due to Lower Book Taxable Income		(13,874)

Sum of Tax Impacts	(68,335)

PGE Exhibit 206
Taxes Other Than Income
2015 - 2019 Test Year

Item	FERC Account	AWO	2015 Actual	2016 Actual	2017 Actual	2018 Budget	2019 Forecast
Payroll Taxes	408.1	Note 1	13,719,102	13,522,625	15,364,666	15,084,350	16,637,391
Property Taxes - Oregon	408.1	4081001	47,797,482	51,759,568	54,415,972	56,699,491	63,712,631
Property Taxes - Washington	408.1	4081002	2,201,144	1,640,162	2,118,221	2,370,228	2,549,148
Property Taxes - Montana	408.1	4081003	5,401,265	5,752,457	4,838,828	6,003,000	5,316,372
Franchise Fees	408.1	4081010, 4081011	43,406,579	43,125,386	43,018,675	44,069,588	47,824,508
Foreign Insurance Excise Tax	408.1	4081012	9,984	9,485	-	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,667,103	1,995,850	2,262,201	2,068,281	2,068,281
Misc. Tax & Lic Fees - Montana	408.1	4081014	441,288	407,253	356,306	458,304	432,504
Total Taxes Other Than Income			114,643,947	118,212,785	122,374,869	126,753,242	138,540,836

Note 1: Payroll Tax accounts include 4081004, 4081005, 4081006, 4081007, 4081008 and 4081009

PGE Exhibit 207
Rate Base ($000s)
Based on Ending 12/31/18 Balances

		12/31/2018 Balance
	Plant in Service	10,221,818
Less:	Accumulated Depreciation/Amortization	(4,761,822)
	Accumulated Deferred Taxes	(679,665)
	Accumulated Deferred ITC	-
Net Utility Plant		4,780,331
Operating Materials and Fuel Stocks		78,945
Deferred Debits		
	Glass Insulators	5,473
	Dispatchable Standby Generation	11,818
Deferred Credits		
	Injuries & Damages	(9,075)
	Customer Deposits	(12,580)
	Incentive Adjustment (UE 283)	(8,000)
	Major Maintenance Accruals	(7,997)
	Post Retirement Liabilities	(44,889)
	Misc. Other	(10)
Working Capital		63,172
Rate Base		4,857,189

PGE Exhibit 208
Rate Base Comparison
UE 319 vs. 2019 Test Year
(000s)

	UE 319 Test Year	Working Cash Requirements	Thermal Plant Maint. Accruals	Plant Additions/ Depr/Amort	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	YE 2018 Rate Base
Plant in Service	9,816,526			405,292			10,221,818
Accumulated Depr/Amort	(4,727,981)			(33,841)			(4,761,822)
Accumulated Deferred Taxes/ITC	(662,272)				(17,393)		(679,665)
Net Utility Plant	4,426,274	-	-	371,451	(17,393)	-	4,780,331
Other Rate Base	24,359		(6,890)			(3,784)	13,685
Working Cash	54,742	8,431	-	-		-	63,172
Rate Base	4,505,374	8,431	(6,890)	371,451	(17,393)	(3,784)	4,857,189

PGE Exhibit 209
Production Tax Credits (PTCs) in 2019 Net Variable Power Cost

Grossed Up for Taxes	(49,026)
Gross Up Factor	1.373
PTCs	(35,715)

PGE Exhibit 210
Unbundled Results of Operations Summary
2019 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,061,408	33,133	638,739	4,832	10,827	70,921	64,762	1,884,622
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	601	14,188	15,333	(4,832)	2	8	28	25,327
Total Operating Revenues	1,062,009	47,321	654,072	-	10,829	70,929	64,789	1,909,949
Operation & Maintenance								
Net Variable Power Cost	375,309	-	-	-	-	-	-	375,309
Total Fixed O&M	169,108	11,275	137,259	-	-	-	-	317,642
Other O&M	62,949	5,111	91,041	-	1,911	54,666	50,350	266,027
Total Operation & Maintenance	607,366	16,385	228,300	-	1,911	54,666	50,350	958,978
Depreciation & Amortization	173,383	14,342	163,745	-	4,500	10,879	5,647	372,496
Other Taxes / Franchise Fee	45,777	2,865	84,806	-	778	1,350	2,965	138,541
Income Taxes	44,015	2,474	35,942	-	644	633	1,089	84,797
Total Oper. Expenses & Taxes	870,541	36,067	512,793	-	7,832	67,527	60,051	1,554,812
Utility Operating Income	191,469	11,253	141,279	-	2,997	3,401	4,738	355,137
Rate of Return	7.31%	7.31%	7.31%	N/A	7.31%	7.31%	7.31%	7.31%
Return on Equity	9.50%	9.50%	9.50%	N/A	9.50%	9.50%	9.50%	9.50%
Rate Base								
Utility Plant in Service	5,305,106	346,884	4,252,013	-	65,649	143,058	109,109	10,221,818
Accumulated Depreciation	2,308,745	162,568	2,162,648	-	17,580	80,627	29,653	4,761,822
Accumulated Def. Income Taxes	461,618	36,079	148,117	-	6,747	16,766	10,338	679,665
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	2,534,743	148,237	1,941,248	-	41,321	45,665	69,118	4,780,331
Operating Materials & Fuel	62,629	726	15,589	-	-	-	-	78,945
Misc Deferred Debits	3,821	5,473	-	-	-	-	-	9,294
Misc. Deferred Credits	(17,855)	(1,994)	(45,412)	-	(648)	(1,887)	(6,759)	(74,554)
Working Cash	35,370	1,465	20,835	-	318	2,744	2,440	63,172
Total Rate Base	2,618,708	153,908	1,932,260	-	40,991	46,521	64,799	4,857,189

UE 335 / PGE / 300
Niman – Kim – Batzler

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Net Variable Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Cathy Kim
Greg Batzler

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Cathy Kim. My position at PGE is Manager, Term and Daily Trading.

My name is Greg Batzler. My position at PGE is Senior Regulatory Analyst, Regulatory Affairs.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2019 Net Variable Power Costs (NVPC). We discuss several of the updates to the parameters (e.g., ancillary service assumptions) from PGE's NVPC forecast for 2018, as well as modeling changes. We compare our initial 2019 forecast with PGE's final 2018 NVPC forecast and explain why the per-unit expected NVPC have increased by approximately $2.31 per MWh.

Q. What is PGE's initial net variable power cost forecast?

A. Our initial 2019 NVPC forecast is $375.3 million, based on contracts and forward curves as of December 21, 2017. This initial 2019 NVPC forecast represents an increase of approximately $39.3 million relative to our final 2018 NVPC forecast.

Q. Will PGE make a separate 2019 test year Annual Update Tariff (AUT) filing?

A. No. The NVPC portion of this general rate case establishes the basis for recovering these costs and will be the 2019 forecast to which we compare the 2019 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?

A. Yes. Public Utility Commission of Oregon (OPUC or Commission) Order No. 08-505 adopted a list of MFRs for PGE to follow in AUT filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 301 contains the list of required documents as approved by Commission Order No. 08-505. Confidential PGE Exhibit 302C provides the initial output files and assumptions. The additional MFRs required as part of our initial filing are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within 15 days of this filing (i.e., March 2, 2018). As with PGE's NVPC filings in the 2018 NVPC proceeding, the MFR documents are designated as either "confidential" or "non-confidential."

Q. What schedule do you propose for NVPC updates in this docket?

A. We propose the following schedule for our power cost update filings:

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; and any errata corrections to our February 15 initial filing;
- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;

- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and
- November – Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; and 2) final update of gas and electric forward curves.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: MONET Model;
- Section III: MONET Updates and Modeling Changes;
- Section IV: Comparison with 2018 NVPC Forecast; and
- Section V: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2019?

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. We built this model in the mid-1990s and have since incorporated several refinements. Using data inputs, such as an hourly load forecast and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Retail load forecast, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, emissions control chemicals, and any variable operating and maintenance costs (although not part of NVPC for ratemaking purposes, except as discussed below);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;
- Physical and financial electric contract purchases and sales; and

- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch; generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Thermal plants can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. In Section III below, we discuss our most recent enhancements to PGE's MONET power cost model.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2018 NVPC proceeding, we include certain variable chemical costs, lubricating oil costs, and we include forecasted federal production tax credits (PTCs). We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2019 NVPC.

III. MONET Updates and Modeling Changes

Q. Does PGE present both parameter updates and modeling changes in this initial filing?

A. Yes. Because this is a GRC proceeding, we include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates.

Q. What load forecast does PGE use in this initial filing?

A. We use the 2019 retail load forecast described in PGE Exhibit 1100.[1] Our forecast is approximately 18.2 million MWh of cost-of-service energy, or approximately 2,078 MWa, a decrease of 17 MWa from the final 2018 test year forecast (Docket No. UE 319).

Q. What updates and model changes does PGE include in this docket?

A. In this initial filing, we include many of the updates typically included in an April 1 AUT filing. Additional items requiring 2017 data, or for which updated data were not available in a timely manner for this filing, will also be updated in our April 1 filing. Among those items is the update to the thermal forced outage rates. We plan to file an update that includes forced outage rates based on 2014 through 2017 data by April 1, 2018, consistent with information that would be used in an initial AUT filing for 2019. By that date, we will have processed the 2017 data needed to complete the outage rate calculations. For this initial filing, we use the same forced outage rates, based on 2013 through 2016 data, from Docket No. UE 319 (UE 319). We will continue to update several of the items included under Schedule 125 as this docket proceeds.

We include the following updates and modeling changes in our initial MONET runs:

[1] PGE's load forecast in this initial filing is consistent with the retail load forecast described in PGE Exhibit 1100. There is a slight difference between reported energy amounts, because MONET uses a calendar-month basis of the load forecast (measured at the busbar). In PGE Exhibit 1100, we describe the forecast on a cycle-month billing basis (measured at the customer meter).

1. Update the estimated NVPC benefit based on PGE's full participation in the Western Energy Imbalance Market (Western EIM);
2. Update Port Westward 2 to use MONET's dynamic programming dispatch model, consistent with the dispatch model used for PGE's combined-cycle combustion turbine and coal plants;
3. Replace the current Mist Gas Storage and Gap Services contract with the North Mist Expansion Project tariff costs;
4. Update California Trading Margins to include a more granular forward looking methodology;
5. Update to the latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study in our hydro data;
6. Update the forecast of transmission resale net revenue; and
7. Include the new capacity agreement acquired through bilateral negotiations pursuant to Commission Order No. 17-494.

Q. What is the net effect on PGE's initial 2019 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is a $17.6 million increase in PGE's initial 2019 NVPC forecast from the base NVPC forecast.

Q. Does PGE discuss any other items that could have an effect on NVPC?

A. Yes. We also discuss a proposed methodology for tracking the online dates of newly forecasted Public Utility Regulatory Policies Act (PURPA) Qualifying Facilities (QFs) in order to refund or collect any difference in timing within a future year's NVPC forecast.

A. Western Energy Imbalance Market

Q. Please describe the Western EIM.

A. The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO). Using software to optimize generator dispatch within and between Balancing Authority Areas (BAAs), the Western EIM identifies sub-hourly transactions (i.e., every 15 and 5 minutes) to serve real-time customer demand and facilitates transfer of excess energy generated in one area to another area where it is needed. This allows Western EIM participants to obtain the least-cost energy to serve their load and to effectively integrate output from variable renewable energy resources. The Western EIM's operations began November 1, 2014.

Q. Which utilities currently participate in the Western EIM?

A. PacifiCorp, Nevada Energy, Puget Sound Energy, and Arizona Public Service are active participants in the CAISO-operated market. As we note below, PGE began participating in late 2017.

Q. Are other utilities planning to enter the Western EIM in the future?

A. Yes. Idaho Power Company and Powerex plan to enter the market in 2018. The Balancing Authority of Northern California (BANC), the Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP) all plan to enter the Western EIM in 2019. Seattle City Light (SCL) and the Salt River Project (SRP) plan to enter the Western EIM in 2020.[2]

Q. When did PGE begin participating in the Western EIM?

A. PGE began successful participation in the Western EIM on October 1, 2017. PGE's

[2] For the 2019 E3 Scenario, SCL, LADWP and SMUD are assumed to join the Western EIM in April 2019. After completing the 2019 Scenario, SCL announced that its expected entry would be in 2020 instead of 2019.

integration into the Western EIM has gone smoothly and early results indicate that PGE has been able to participate effectively in the Western EIM. Consistent with FERC Orders, the CAISO files informational reports on market performance during an EIM Entity's transition period (i.e., first six months). These reports show that market prices have been stable and within reasonable ranges. They also show that PGE has consistently passed resource sufficiency tests during nearly all intervals.[3]

Q. The stipulation resolving NVPC issues in UE 319 stated that PGE would "complete a Western EIM cost-benefit study to be used in its 2019 AUT filing." Please summarize the Western EIM issue(s) raised in UE 319.

A. In UE 319, PGE engaged Energy + Environmental Economics (E3) to model a 2018 gross benefit for PGE's test year power costs, which PGE included in the 2018 NVPC forecast. PGE also included the net benefits of the full self-integration of its wind resources as a benefit related to Western EIM participation. However, OPUC Staff argued that only the <u>direct</u> benefits should be set to equal the <u>direct</u> costs of participating in the Western EIM until PGE has more accurate results from the market. For settlement purposes, parties agreed to increase the direct benefits of the Western EIM by $0.5 million. PGE also agreed to complete a Western EIM cost-benefit study to be used in its 2019 AUT filing.

Q. Has PGE addressed this issue in its initial filing in this proceeding?

A. Yes. PGE has again engaged E3 to model a 2019 gross benefit of Western EIM participation for PGE's test year power costs. E3's study is included as PGE Exhibit 303. Similar to the 2018 study, the 2019 study is structured as an addendum to the 2015 study

[3] The informational reports are available under FERC Docket No. ER15-2565.

(which was based on a 2020 study year).[4] The modeled gross benefit (less a forecast of transaction settlement charges) is included in PGE's test year power costs. The modeled gross benefit is $4.5 million (2015 $) in the E3 study.

Q. How do the 2019 study results compare to prior studies completed by E3?

A. In general, PGE's benefit result is similar to the cost savings observed in the prior studies completed by E3. When compared to the 2018 study, the 2019 study results are approximately 11% ($0.6 million) lower.

Q. Did PGE update the inputs in the 2019 study?

A. Yes. In the 2019 study, PGE updated several categories of inputs.[5] For example, PGE updated the market topology for new participants, revised generation plant parameters to reflect more current capabilities, and revised 2019 gas prices (which are lower than the gas price projections used in PGE's 2018 study). PGE also sought to model PGE's use of the PACW[6]-to-PGE path in a manner that reflects PGE's decision to offer firm transmission rights for Western EIM transfer during all market periods.

Q. How does PGE use the PACW-to-PGE path for Western EIM transfers?

A. As part of its FERC filing that sought approval to participate in the Western EIM using market-based rates, PGE committed to offer 200 MW of firm transmission rights for Western EIM transfers during all market periods. In its filing, PGE also stated that the rest of its long-term transfer capability on the path would also be made available for Western EIM transfers, subject to usage for reliability or servicing existing contractual arrangements.

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[4] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf).
[5] PGE Exhibit 303 describes the input data changes.
[6] PacifiCorp West Balancing Authority.

FERC approved PGE's filing prior to our October 1, 2017 market entry. Therefore, in the 2019 study, PGE sought to model this commitment by holding a portion of the transmission capacity on the PACW-to-PGE path unscheduled in the day-ahead and hour-ahead model stages, which enables more opportunities for PGE to import power in the real-time model stage. In the 2019 study, PGE held back 276 MW of long-term firm transmission rights, the amount PGE held at the time of its market-based rate filing. The 'hold back' of 276 MW of transmission rights resulted in an increased savings of approximately $0.5 million in the 2019 study.

Q. Please describe the benefits that PGE estimates through the 2019 study.

A. PGE estimates sub-hourly dispatch savings. Sub-hourly dispatch savings result from PGE's ability to export and import in near real-time with other Western EIM participants to respond to intra-hour imbalances. PGE imports power from the Western EIM to avoid production costs on its more expensive thermal generators when EIM prices are low. PGE exports power to the Western EIM, earning net revenues, when EIM prices are higher than PGE's generation production costs.

Due to load and resource diversity across the Western EIM footprint, PGE also can attain sub-hourly dispatch savings through lower flexible ramping requirements in the real-time market. While the Western EIM includes design elements to ensure that PGE has sufficient resources to serve the energy and capacity needs of its customers, prior to commencing each hour, CAISO calculates a flexible ramping requirement for the entire Western EIM footprint that can be less than the sum of the individual participants' flexible ramping requirements (i.e., a Western EIM Diversity Benefit). This lower flexible ramping requirement can provide PGE with additional dispatch flexibility and lead to greater sub-hourly dispatch cost savings.

Q. How do these forecasted direct benefits compare to the forecasted direct costs of participating in the Western EIM for 2019?

A. The forecasted direct costs of Western EIM included in PGE's 2019 revenue requirement are approximately $5.4 million. This compares to forecasted direct benefits of approximately $4.6 million, which are included as a reduction to power costs. Table 1 below summarizes the 2019 direct benefits and costs related to PGE's Western EIM participation.

Table 1
2019 Direct Benefits and Costs Related to Western EIM Participation

	NVPC Net Benefits		**Western EIM Costs in 2019 Test Year***	
1	Western EIM Gross Benefit (2015$)	$4.5 million	Annual Fees (IT)	$0.5 million
2	Escalation of Gross Benefit to 2019 $	$0.5 million	Incremental Labor	$1.5 million
3	Less Settlement Charges (CAISO)	($0.3 million)	Amortization Expense	$2.6 million
4	-	-	Property Taxes	$0.1 million
5	-	-	Return on Rate Base	$0.7 million
	Total (2019 $)**	**$4.6 million**	**Total (2019 $)**	**$5.4 million**

** The costs shown under "Western EIM Costs in 2019 Test Year" are not part of PGE's initial 2019 NVPC forecast. They are included in other parts of PGE's 2019 test year revenue requirement.*
***Numbers may not sum due to rounding.*

Q. How have the forecasted costs of participating in the Western EIM changed from amounts estimated in 2018?

A. As seen in the table above, PGE's 2019 test year costs for Western EIM total $5.4 million for 2019, which is approximately $0.9 million below the UE 319 2018 forecast of $6.3 million. This is primarily due to: 1) a slight reduction in rate base leading to a reduction in depreciation expense and carrying costs for 2019, and 2) a slight reduction in incremental labor costs.

Q. Other than the benefits quantified in the E3 study, does PGE's participation in the Western EIM produce any other benefits?

A. Yes. Participation in the Western EIM has also enhanced PGE's ability to efficiently integrate variable renewable resources on an intra-hour energy basis. Previously, PGE paid the Bonneville Power Administration (BPA) via its variable energy resource balancing service (VERBS) to provide capacity for regulating reserves, following reserves, and imbalance reserves. However, participating in the Western EIM helps PGE affordably assume responsibility for fully integrating its own wind resources. By balancing the variability of wind and load across a broader footprint, the Western EIM not only reduces curtailments of renewable energy, but also can provide PGE with additional dispatch flexibility through the Western EIM Diversity Benefit described above.

The Western EIM can also enhance reliability. In 2013, a FERC Staff Report addressed the reliability value an EIM could provide. In the paper, FERC focused on the ways an EIM could reduce the chance of a loss of load event. One example identified in the FERC Staff Report was enhanced situational awareness as a byproduct of the models CAISO uses in the real-time market. While the models utilized to run CAISO's real-time market are not reliability tools themselves, by recognizing any operational limits of generation and transmission facilities and proactively signaling resources to respond to system imbalances at 5- and 15-minute intervals, the Western EIM can correct potential issues quickly, and potentially resolve issues on the system before they elevate to a level that would require involvement from another entity such as the Reliability Coordinator.

Q. In summary, what are the direct Western EIM benefits and costs included in PGE's initial 2019 NVPC forecast?

A. After escalating the E3 study results to 2019 dollars, PGE's forecasted NVPC includes a direct gross benefit of approximately $5.0 million, less forecasted settlement costs of approximately $0.3 million. This amounts to a net benefit in PGE's NVPC forecast of $4.6 million.

Q. What indirect benefits are included in PGE's initial 2019 NVPC forecast?

A. While not included in Table 1, the net savings included in PGE's NVPC forecast related to full self-integration of its wind resources is approximately $4.5 million.[7]

Q. In summary, what other Western EIM costs are included in PGE's 2019 test year?

A. The other Western EIM costs in PGE's 2019 test year consist of PGE's ongoing O&M and the costs associated with capital. In total, we forecast these costs to be $5.4 million in the 2019 test year. The costs are listed by category in Table 1 above.

B. Port Westward 2 Switch to Dynamic Programming Dispatch Model

Q. Please briefly describe the Port Westward 2 (PW2) dispatch model used in recent AUT and GRC NVPC proceedings.

A. For economic energy dispatch, PW2 was modeled using the "up/down" hourly dispatch logic in MONET. The hourly dispatch logic for PW2 relies on an annual heat rate, monthly capacities, variable O&M, chemical costs, forward price curves, and other parameters to dispatch the plant when the cost of generating is less than the market price for electricity in a given hour. For economic energy dispatch, each hour the entire plant is either dispatched to full capacity or offline.

[7] VERBS 30/15 savings less full self-integration costs for 2019.

Q. Why is PGE proposing a change to the dispatch modeling of PW2?

A. The latest plant parameter sheet for PW2 includes a start-up cost, which cannot be modeled using the current “up/down” logic in MONET. All of PGE’s combined-cycle combustion turbine and coal plants in MONET utilize its dynamic programming (DP) logic, as it more accurately models the actual operations of the plants.

Q. Please explain the enhanced dispatch model used for this filing.

A. For this initial filing, PGE has switched PW2 from the original “up/down” hourly dispatch logic to the existing DP model. The DP model achieves dispatch decisions that maximize the plant’s value over the model run period, in this case the year 2019, while accurately incorporating operational constraints. PGE has provided information regarding the DP dispatch model in the MFR documents accompanying prior AUT filings, and we provide additional detail with the MFRs for this filing.

Q. Please briefly describe dynamic programming.

A. As we have discussed in prior AUT and GRC filings, DP is a computational approach to multi-stage decision problems. The "stages" in the current problem are the hours for which a decision must be made to dispatch or not dispatch the plant.

Q. How does this more accurately reflect plant operational constraints?

A. The DP dispatch algorithm more closely mirrors actual plant operations than the previous dispatch model. The DP model can take account of ramp-up and ramp-down constraints, minimum commitment times, start-up costs, and varying heat rates.

Q. Does the switch to the DP dispatch model for PW2 affect PGE’s initial 2019 forecast?

A. No. The enhancement to switch the PW2 dispatch model to DP by itself has no effect on PGE’s initial 2019 NVPC forecast. PW2 on DP with no parameter updates dispatches exactly the same as the "up/down" logic. However, changes to the plant parameters will affect the forecast.

Q. Has PGE updated the PW2 parameters along with making the switch to DP?

A. PGE has updated only a single plant parameter for PW2, specifically the introduction of the start-up cost, which is the reason for switching PW2 to DP at this time. The start-up cost is taken from the February 3, 2017 (as used in the March 31 update filing for the 2018 GRC) plant parameter sheet provided by PGE's Power Supply Engineering Services department. We will update other PW2 parameters as needed, such as capacities, heat rates, variable O&M costs, and ancillary service capabilities, in the April 1 update filing using the most current plant parameter sheet.

Q. What effect does the addition of the PW2 start-up cost have on PGE's initial 2019 NVPC forecast?

A. The addition of the PW2 start-up cost increases PGE's initial 2019 NVPC forecast by approximately $0.8 million.

C. North Mist Expansion Project

Q. Please briefly describe the North Mist Expansion Project.

A. In 2012, PGE entered into a Precedent Agreement with NW Natural for long-term, no-notice gas storage services from North Mist Expansion Project (NMEP).[8] PGE is currently using storage from Mist at the Port Westward/Beaver complex to augment gas pipeline transportation service to PGE's Beaver Plant and Port Westward Plant (Units 1 and 2). PGE's current capacity at Mist is subject to recall as NW Natural intends to use its

[8] The North Mist Expansion Project was previously referred to as the Emerald Facility or Emerald Project.

existing Mist storage to serve its core customers.[9] The gas storage services from NMEP will (in conjunction with the Kelso-Beaver pipeline) meet the fueling requirements of the Port Westward/Beaver complex and replace the current natural gas storage services provided by NW Natural (i.e., Mist). Natural gas-fired resources are typically fueled with firm transportation that is equivalent to the plant's expected dispatch or its maximum generation capability. However, PGE's observation with the Port Westward and Beaver sites is that, in practice, a combination of firm transport and natural gas storage can provide a more flexible and lower cost solution than exclusively using firm transport to supply all the needs of the plants.

Q. Did PGE discuss the NMEP in previous Commission proceedings?

A. Yes. PGE proposed to add NMEP-related costs in its 2018 NVPC forecast filed in UE 319. PGE's 2018 NVPC forecast was approved by Commission Order No. 17-384.

Q. Were any issues raised in UE 319 regarding NMEP?

A. The only issue regarding the NMEP was the reasonableness of the two-month overlap between the NMEP in-service date and the conclusion of Mist "gap services". The Stipulating Parties[10] agreed that it is reasonable for PGE to reduce its 2018 NVPC forecast by $97,000 while continuing to model a two-month overlap in MONET. The Commission approved that Stipulation.

[9] See page 1.10 of NW Natural's 2014 Integrated Resource Plan for a description of Mist Recall. Commission Order No. 15-064 acknowledged NW Natural's 2014 Integrated Resource Plan.
[10] OPUC Staff, Oregon Citizens' Utility Board (CUB), Industrial Consumers of Northwest Utilities (ICNU), and PGE.

Q. Why is it important to have a two-month overlap between NMEP in-service date and the conclusion of Mist "gap service"?

A. PGE is planning the overlap of two months between the NMEP in-service date and the conclusion of Mist "gap service" to ensure that PGE can reliably provide firm fuel supply to the entire Port Westward/Beaver complex. Without the overlap, PGE would need to entirely draw down the gas at Mist before NMEP goes into service during a critical time of year (winter of 2018-2019) when natural gas supplies are constrained. If the NMEP was delayed for any reason beyond the expected in-service date, a portion of PGE's fuel supply would be non-firm and PGE would not be positioned to provide reliable service from the Port Westward/Beaver complex if generation is needed at levels greater than what fuel supply from PGE's contracted pipeline transportation service can support.

Q. What changed with the NMEP since parties signed the Stipulation in UE 319?

A. At this time, the only variable that changed is the NMEP in-service date. Based on NW Natural's project schedule, PGE initially anticipated the NMEP would be placed into service by October 1, 2018 and modeled this date in its initial 2018 NVPC forecast and subsequent 2018 NVPC forecast updates on March 31, July 10, and September 29, 2017. However, due to the Engineering, Procurement, and Construction (EPC) contractor falling behind schedule,[11] in October 2017 the NMEP expected in-service date was likely to be delayed and probably would not be in service before the end of 2018, but in early 2019 instead. Therefore, PGE removed the costs associated with NMEP from its November 6, 2017 update of its 2018 NVPC forecast[12] and modeled a January 1, 2019 NMEP in-service date in the initial 2019 NVPC forecast. Table 2 below lists key milestones, both completed and

[11] See detailed discussion regarding the delay on the following pages.
[12] The $97,000 stipulated reduction associated with NMEP overlap with Mist "gap services" was not removed.

estimated, to support the updated time when NMEP is currently projected to be placed in service.

Table 2
North Mist Expansion Project Milestones

Milestone	Actual/Scheduled Completion
PGE Provides NW Natural with Notice to Proceed	September 30, 2016*
Initiate Drilling of First Well	November 2016*
Completion of Well Drilling	July 2017*
EPC Contractor Mobilizes Onsite and Starts Construction	August 2017*
Completion of Major Construction Activities	May 2018
Inject Base Gas and Working Gas into Reservoir	February 2018 through January 2019
Commissioning Activities for Pipeline and Compressor Station	June 2018 through January 2019
Project In-Service	January 2019

** Asterisk identifies Actual Completion dates*

Q. What are the factors underlying the delay?

A. The most significant factors for the delay are:

- The EPC contractor fell behind in their engineering schedule, which delayed site mobilization for construction by several months.
- Hurricane Harvey affected the EPC Contractor's operations and those of their subcontractors in Houston, delaying the delivery of necessary components.
- An above average number of fire danger restrictions for work in the forest land due to the dry summer/fall months.
- Challenges during horizontal directional drilling activities (e.g., failure of conduits during pull-backs).
- Challenges with the site preparation work at the compressor station.

Q. What is the NMEP cost impact in the initial 2019 NVPC forecast?

A. Service under the agreement will increase PGE's 2019 power costs in its initial NVPC forecast by approximately $15.1 million. This increase includes the power cost impact of concluding Mist "gap service" two months after the modeled NMEP in-service date of January 1, 2019.

Q. Do you expect changes in NMEP project costs and consequently in PGE's 2019 power costs related to NMEP?

A. Yes. As project work continues, we expect the actual costs to change. We will update our cost estimate with more current information in forthcoming NVPC updates.

Q. Is NMEP the least-cost option for PGE's gas fueling needs at the Port Westward/Beaver complex?

A. Yes. Table 3 summarizes PGE's fueling sources prior to (and after) the addition of PW2. Our alternative to the NMEP storage would be to fuel the plants with more firm gas transportation, but any viable alternative would need to replace 120,000 dekatherms per day of NMEP storage, which provides no-notice storage service.

Table 3
Beaver/Port Westward Site Fueling

Fueling Source (Dth / Day)	Prior to PW Unit 2	During Gap Services	After NMEP
Mist Storage*	70,000	90,000	120,000
Firm Gas Transport	103,305	103,305	103,305
Delivered Gas	14,195	39,195	9,195
Total Fuel Position	187,500	232,500	232,500

**Maximum withdrawal quantities; Subject to ratcheting once inventory level drops below 50%*

According to the Williams NW Pipeline's most current list of available capacity, there is no available transportation capacity to the Kelso-Beaver delivery point. Also, based on proposed expansion rates published by the Williams NW Pipeline, firm gas transportation would be $24.5 million per year.[13] The estimated yearly costs associated with NMEP are less.[14]

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[13] $24.5 million = 120,000 dekatherms per day multiplied by $0.56 per dekatherm per day.
[14] See PGE's confidential MFRs for an estimate of the first-year costs associated with NMEP storage.

Additionally, due to scheduling and operational constraints on its system, the Williams NW Pipeline cannot provide the intra-day scheduling flexibility that the no-notice storage service can provide. The no-notice service provides PGE with a highly flexible and dynamic fuel supply to meet the demands for peaking, load following, and wind integration services.

D. California-Oregon Border (COB) Trading Margins

Q. The stipulation resolving NVPC issues in UE 319 stated that PGE would "propose a more granular forward-looking method of forecasting California trading margins, which will be included in PGE's 2019 AUT filing." Please summarize the California trading margin issue.

A. Staff had argued that PGE's method for forecasting a COB trading margin is understated because PGE did not account for the intra-monthly variability of prices in its forecasting method. Staff argued that within a month, the COB/Mid-Columbia (Mid-C) margin[15] can vary considerably and that PGE conducts more transactions when the margin in either direction is greater. As a consequence of using a monthly average price, Staff argued that customers receive no value for economic COB purchases and that customers receive a reduced value from sales at COB.

Q. Has PGE addressed this issue in its initial filing in this proceeding?

A. Yes. PGE has included modeling in MONET that uses hourly data to take a more granular approach to estimating (under normal conditions) the net power cost benefits that could be attained by PGE utilizing its firm transmission access to sell or purchase power at the COB market (i.e., California trading margins). By taking a more granular view of forward prices

[15] The market price difference between transactions at COB and transactions at Mid-C.

at COB and Mid-C, PGE's new approach captures both intra-monthly value and forecasts both purchases and sales.

Q. How does PGE propose to forecast California trading margins in the 2019 NVPC forecast?

A. PGE proposes to continue including a pro forma contract in MONET, recognizing PGE's ability to purchase at Mid-C and sell at COB and vice versa (depending on prevailing forward price curves). The pro forma contract's value will be the result of a modeled <u>hourly</u> purchase or sale for each month of the year.

To value the pro forma contract, we use shaped hourly forward curve prices for the Mid-C and COB trading hubs to forecast the price margin. Similar to UE 319, we forecast the pro forma contract quantity based on an analysis of historical trading volumes.

Q. Please describe PGE's method to forecast the pro forma contract quantity under normal conditions in the 2019 NVPC forecast.

A. We continue to forecast the quantity of purchases and sales as we have in the last two NVPC proceedings (Docket Nos. UE 308 and UE 319), with one modification. We continue to use a rolling three-year average of actual day-ahead trading data from PGE's trading data information system. However, we modify the data set from consisting of one monthly on- and off-peak purchase or sale, to 24 separate purchases or sales for each month. This change in granularity results in the forecast using 288 different data points for both purchases and sales.

Q. Please describe PGE's method to forecast COB prices in the 2019 NVPC forecast.

A. We propose to continue PGE's forward curve methodology, which we have used for the creation of PGE's forward price curves in past AUT and GRC proceedings, with one modification. While we still use the monthly forward prices for Mid-C and COB that are generated by the term power trading desk, we now shape the monthly prices into hourly prices to value the pro forma contract. For the Mid-C, we use the shaped hourly forward prices generated by the Lydia program, which MONET currently uses to model the hourly dispatch of PGE's resources. For COB, we use the weighted average shape of PGE's historical day-ahead COB prices to impose an hourly shape on the monthly on/off-peak COB forward price curve. As a result, PGE's hourly forward curve for COB exhibits a shape similar to that of historical prices, with more weight given to higher volume trades. Consistent with the period used for trading volumes, we propose using a rolling three-year average of day-ahead prices to shape PGE's COB curve.

Q. Is PGE's method still intended to estimate results under normal conditions?

A. Yes. The basic principle of MONET is to produce a final test year forecast of NVPC that reflects a baseline (or deterministic) forecast of all variables, including sales from (and purchases for) PGE's resource portfolio under normal conditions (e.g., plant operations, water and wind flows, and weather).

Q. What effect does this proposed method have on PGE's initial 2019 NVPC forecast?

A. PGE's proposed method results in a forecast of approximately 1.4 million MWh sold and 12,931 MWh purchased, producing an NVPC benefit of approximately $6.1 million, an increase of $0.4 million over using the previous method with the same curve snapshot. Additional details behind our forecast can be found in our MFRs.

E. Transmission Resale Net Revenue

Q. How does MONET treat transmission sales for resale for 2019?

A. Similar to our 2018 NVPC forecast, PGE has not executed any long-term transmission resale contracts for 2019. As such, we continue to include a forecasted net benefit related to transmission sales for resale that is similar in construct to the method used and described in UE 319.

Q. Please describe how PGE's transmission sales for resale continue to change.

A. PGE continues to see limited demand and low prices for this service. Additionally, PGE is experiencing a lack of transmission capacity during certain times of the year. As a result, PGE is reserving more transmission rights in order to meet load during the high temperature months of July through September. We have also seen an increase in the need to purchase additional short-term transmission from the market during this time. Further adding to the lack of sales during the summer are additional transmission derates[16] from BPA, resulting in greater congestion on certain paths. These derates, in particular, cause increased congestion on the South of Allston (SOA) path, which directly affects our Port Westward and Beaver generating facilities.

Q. Please describe how these derates impact PGE's transmission capacity.

A. During times of summer congestion, including during the times that BPA has implemented its SOA Bilateral Redispatch pilot project,[17] BPA has begun eliminating hourly firm sales and hourly redirects. The impact to PGE during these periods is significant in that we are unable to redirect transmission rights on any path that has a material adverse impact on SOA. This includes most of the transmission PGE holds for remote resources. From an operational standpoint, this limits PGE's flexibility during peak load events, limits our access to the market for purchases, and limits our ability to adapt to plant outages.

[16] The reduction of rated transfer capability.
[17] See https://www.bpa.gov/transmission/customerinvolvement/non-wire-soa/Pages/default.aspx for additional information.

For example, during the 2017 summer heat waves, PGE had very little wind generation, but was unable to redirect transmission for market purchases because BPA had eliminated hourly transmission sales and hourly redirects on the SOA path and any path that impacted the SOA path. Additionally, during one of these events, the Boardman plant experienced a forced outage, which left PGE with 717 MW of transmission at the wind plants <u>and</u> 500 MW of transmission at Boardman that we were unable to use. Furthermore, as BPA would not allow a redirect off the Trojan path, we had to purchase non-firm transmission to serve load, while holding over 1,200 MW of long-term firm transmission rights we could not use.

Q. Has PGE addressed these transmission redirect changes in MONET?

A. Yes, to some extent. To address this shift in actual operations, PGE has updated its forecast to only include a transmission sales for resale estimate for nine months of the year. We have excluded the months of July, August, and September, when PGE is most reliant on holding transmission capacity to meet peak load and least able to resell or redirect existing long-term firm transmission. The MFRs provide additional details behind the forecast of transmission resale net revenue.

Q. What effect does this have on PGE's initial 2019 NVPC forecast?

A. Removing the third quarter from our forecast of transmission resale net revenue increases PGE's initial 2019 NVPC forecast by approximately $0.7 million.

Q. Does PGE expect to update transmission resale net revenue later in this case?

A. Similar to UE 319, if PGE does secure a new long-term transmission resale agreement before the conclusion of this proceeding, we propose to replace our current estimate with the terms of that agreement.

F. Pacific Northwest Coordination Agreement Study Update

Q. Please describe the update to include the new PNCA study.

A. Under the PNCA, the Northwest Power Pool (NWPP) conducts an 80-year regulation study called the Headwater Benefits Study (HB Study), based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 80 water years under historical stream flows,[18] which we then use, with a set of adjustments, to develop the average hydro energy inputs to MONET. For this filing, we updated from the 2013–2014 HB Study to the 2016–2017 HB Study to establish base average expected outputs for our hydro resources. We then adjusted these base figures using essentially the same adjustment steps used to develop hydro inputs to MONET in prior filings (such as removing PGE hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content).

Q. Why wasn't this study updated in UE 319?

A. During the validation of the 2015-2016 HB Study results, PGE uncovered an issue affecting the upstream storage flows to the Mid-C projects in a manner that was inconsistent with storage releases at or above the Mid-C projects or the storage flows downstream to McNary. This seemed to be a material error in the study. After the discovery, PGE began working with the NWPP to isolate and either explain or (if necessary) correct the root cause of this issue. However, as progress toward solving the issue took considerable time, the Industrial Customers of Northwest Utilities (ICNU) argued that it would be unfair to parties to allow

[18] Using stream flow data from August 1928 through July 2008.

PGE to update the HB Study, after parties filed their opening testimony. For settlement purposes, parties agreed that PGE would continue to use the 2013-2014 HB Study for the purposes of forecasting 2018 NVPC.

Q. Has PGE resolved the issue discovered in the 2015-2016 HB Study?

A. Yes. After a lengthy examination of the files, the NWPP discovered that an error was introduced when they recompiled the model source code to run on 64-bit architecture. An unused routine within the 32-bit version was inexplicably activated within the 64-bit version, resulting in the erroneous increased upstream flows. While the NWPP was unable to determine why this unused routine was being activated within the 64-bit version, they have found that the model appears to work correctly if the unnecessary input file and control file references to it are deleted. As a result, the output from the 64-bit version of the model now matches the output from the 32-bit version and the error is resolved.

Q. What effect does the PNCA-related update have on PGE's initial 2019 NVPC forecast?

A. Updating to the 2016-2017 HB Study increases PGE's initial 2019 NVPC forecast by approximately $0.3 million.

Q. Do you plan to update the HB Study further in this proceeding?

A. We are currently evaluating the monthly shaping of generation in the HB Study results for a possible adjustment to seasonal reservoir drafts to make the monthly shaping more reflective of historically observed shaping in actual generation. We last made a similar adjustment to the HB Study in our 2009 GRC NVPC forecast (Docket No. UE 197). If we make such an adjustment, it will be included in our April 1 update filing.

G. Capacity Agreement

Q. Please discuss the background leading up to PGE pursuing bilateral negotiations for short- to medium-term capacity resources.

A. PGE's 2016 Integrated Resource Plan, filed in November 2016, identified a capacity need of up to 850 MW in 2021, after taking into account proposed demand- and supply-side action items and accounting for imports and executed PURPA QF contracts for facilities not yet online. PGE provided an update of this need to 561 MW primarily due to the following:

- In March 2017, PGE executed a 10-year Power Purchase Agreement (PPA), that will begin on September 1, 2018, with Douglas County Public Utility District for output from the Wells Hydroelectric Project, located in the state of Washington, which is expected to reduce PGE's capacity need by 135 MW;
- Incorporation of PGE's December 2016 load forecast update reduced the capacity need by 71 MW; and
- A capacity reduction of 52 MW due to the execution of additional PURPA QF contracts for approximately 143 MW of nameplate capacity that were executed between June 1, 2016 and December 31, 2016 with projects that include solar, biomass, and geothermal resources.

Furthermore, based on feedback from the Commission, OPUC Staff, and stakeholders, PGE began pursuing bilateral negotiations with owners of existing regional resources to fill its capacity need.

Q. What additional steps did PGE pursue towards the completion of bilateral negotiations?

A. In August 2017, PGE filed a request to waive the Commission's Competitive Bidding

Guidelines that call for a competitive bidding process for resources greater than 100 MW and a term of more than five years. In that filing, PGE requested the Commission grant a waiver to facilitate the purchase of 350 MW to 450 MW of top-performing resources. PGE anticipated that executing bilateral agreements in addition to executing additional qualifying facilities, procuring energy storage in compliance with House Bill 2193, and realizing the capacity contribution from incremental renewable resources actions would address PGE's medium-term capacity needs. PGE received OPUC acknowledgement for the waiver on December 5, 2017, with Commission Order No. 17-386 ultimately granting PGE's waiver conditioned on a requirement that PGE engage the Commission before advancing offers not identified in the top five ranked indicative offers as presented in the waiver application.

Q. Is the contract included in Step 0H of PGE's 2019 initial NVPC forecast one of the top five offers as presented in Docket No. UM 1892?

A. Yes. The contract included in Step 0H of our 2019 initial NVPC forecast is one of the top five scoring offers presented in UM 1892.

Q. Please briefly describe the resource acquired.

A. In short, PGE has entered into a PPA with a counterparty for firm capacity totaling 100 MW and backed by a physical resource. The contract term is five years beginning in 2019 and ending in 2024. The MFRs provide additional details of this capacity contract along with the net change to PGE's initial 2019 NVPC forecast.

H. Qualifying Facilities

Q. What are Qualifying Facilities?

A. Under the PURPA regulations and through ORS 758.505 *et seq.*, PGE is obligated to enter into PPAs with QFs. The federal government enacted PURPA in 1978 to promote, among others, energy conservation, increased efficiency in the use of facilities and resources by electric utilities, and equitable rates for electric consumers. To accomplish these goals, PURPA established a new class of generating facilities (i.e., QFs), which would receive special rate and regulatory treatment. QFs are generating facilities that fall within the following two categories: 1) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or 2) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of both forms of energy.[19]

Q. How does PGE model QF PPAs in the 2019 initial NVPC forecast?

A. In general, unless we have better information available, PGE models QF contracts to begin production based on the Commercial Operation Date (COD) specified in the contract, which is selected by the PPA seller. The achievement of Commercial Operation triggers the applicable on/off-peak avoided cost prices per the executed contract. An example of better information is communication from a QF indicating that it will not meet the contract-specified COD due to project delays. Delays may be a result of interconnection related construction, permitting, or obtaining firm long-term transmission. If a QF PPA has an expected COD on or before December 31, 2019, then the associated QF energy and payments are included in the 2019 NVPC forecast. Costs only include the period in which PGE expects the QF to be operational during the test year. For example, if PGE expects the QF to achieve commercial operation on December 1 of the test period, then the net costs

[19] See https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp for additional information.

associated with energy deliveries from December 1, 2019 through December 31, 2019 are included in NVPC.

Q. Is the use of COD a change in modeling when compared to the 2018 NVPC forecast?

A. Yes. In the 2018 NVPC forecast, PGE modeled QFs coming online based on their Initial Delivery Date (IDD). The IDD occurs prior to the COD with the time period in-between used for project testing. To align with industry standards, PGE is changing QF modeling from IDD to COD.[20]

Q. How many new QF PPAs does PGE include in the initial 2019 NVPC forecast?

A. PGE's 2019 NVPC forecast currently includes 25 new QF PPAs that indicate delivery in 2019.

Q. What is the power cost impact of the 25 new QF PPAs?

A. Including the new QF PPAs in MONET increases PGE's initial 2019 NVPC forecast by approximately $2.6 million.

Q. Besides these 25 new QFs in 2019, is there additional QF energy generation in the 2019 forecast that was not present in the 2018 final NVPC forecast?

A. Yes. In addition to the 25 new QFs in the 2019 forecast that were not present in the 2018 forecast, there are 25 other QFs that were forecast to come on-line sometime during 2018, resulting in a partial year of generation in the 2018 forecast. For the 2019 forecast, these other 25 QFs are present for the entire year. This results in additional energy generation from those QFs in 2019 relative to 2018.

[20] Prior to the COD, QF energy is paid at the off-peak avoided cost price.

Q. What is the combined power cost effect of the 25 new QFs and the additional energy resulting from the other 25 QFs having full-year generation in 2019 vs. part-year in 2018?

A. The combined effect on the 2019 NVPC forecast of the 25 new QFs and the additional energy generation from the other 25 QFs is a total increase of $4.6 million.

Q. Does PGE update the status of QF on-line dates in power cost updates?

A. Yes. PGE receives notices from QF developers regarding the status of their QF project. We also perform an internal assessment to determine the likelihood that a proposed project will achieve their stated COD. As this new information becomes available, PGE updates the status of QF PPAs during NVPC updates in order to reflect any known changes to a QF estimated COD. For example, in the November 6, 2017 update to 2018 NVPC, we updated the forecasted on-line dates for 18 different Solar QFs to reflect expected COD delays.

Q. Does PGE expect that in 2019 all QFs will be in-service at their scheduled COD?

A. As of this filing, PGE has no supplemental information that would lead us to change any 2019 QF CODs from those provided in the sellers' contracts. However, new QFs can encounter any number of constraints that might prevent them from achieving their scheduled COD. For example, QFs that are on-system (i.e., in PGE's service territory) might face constraints related to permitting, while QFs that are located off-system (i.e., outside of PGE's service territory) might face constraints due to transmission. Additionally, the Schedule 201 Standard Contract allows for a cure period up to 12 months for projects that have failed to achieve COD. During this cure period, if market power prices exceed the contract rate, the Seller is obligated to pay a penalty representing the difference between contract and market to protect PGE and its customers.

Q. What actions has PGE undertaken to stay informed on whether a QF will come online by its scheduled COD?

A. PGE developed internal assessments to determine the likelihood a QF project will achieve the COD by the date reflected within the executed contract. As part of this assessment, PGE is reaching out periodically to QF PPAs that have executed contracts, but have yet to achieve commercial operation, to inquire about the status of multiple milestones such as interconnection, permitting, or transmission. The assessment evaluates whether all remaining open milestones needed to achieve the COD can be completed by the proposed COD based on the seller provided information.

Q. Has the issue of forecasted online dates for QFs been raised in other recent NVPC proceedings?

A. Yes. The Oregon Citizens' Utility Board (CUB) raised this issue in PacifiCorp's 2017 and 2018 Transition Adjustment Mechanism (TAM) filings (i.e., Docket Nos. UE 307 and UE 323). CUB proposed two methods to address the issue of QFs not achieving COD:

1. Applying a Contract Delay Rate (CDR)[21] to QFs projected COD in the test period, or
2. Deferring the costs associated with QFs that did not become operational at their expected COD.

Q. What was the resolution in PacifiCorp's 2018 TAM filing (Docket No. UE 323)?

A. The Commission approved CUB's CDR method through Commission Order No. 17-444. In effect, PacifiCorp will use a three-year rolling average of delays to compute a CDR, apply it to reported QF CODs, and adjust the TAM year forecast based on the delay days within the

[21] See Docket No. UE 323, CUB Exhibit 100, page 10.

TAM year.

Q. Does assuming a three-year average of contract delays work for PGE?

A. No. First, PGE does not have sufficient historical information[22] on which to base a three-year average. Second, we believe this approach still does not accurately forecast the actual online delivery dates for new QF contracts. Additionally, we believe the majority of new QFs are more likely to achieve their scheduled COD. This is because attractive contract prices have changed who is developing these projects from small family enterprises to large sophisticated organizations that have stronger balance sheets and greater ability to overcome solar tariffs and timing challenges.

However, due to the recent growth in the number of new QF contracts that PGE expects will achieve COD beginning in 2018, we recognize that accurate forecasting of CODs could become an issue that materially affects our NVPC forecast. Therefore, in order to address this burgeoning issue, we propose the use of a tracking mechanism that is similar in approach to CUB's deferral proposal in Docket No. UE 323.

Q. How do you propose to mitigate the risk of QFs not meeting their expected COD?

A. Given the obligation under federal and state law to provide a market for the electricity produced by small power producers and co-generators, PGE believes that neither PGE nor its customers should bear the risk of forecasting an online date of delivery. As such, PGE proposes to track and true up the actual online dates of newly forecasted QFs with the online date used in MONET's NVPC forecast. In other words, on a going forward basis, PGE proposes to track the actual online dates of all newly forecast QFs with the purpose of either refunding to, or collecting from customers the difference between forecasted and actual

[22] Only 26 QF PPAs were signed by PGE from 1978 (PURPA implementation) through year end 2015.

online dates. This collection or refund would then be included with the next scheduled AUT filing.

Q. Please describe this QF tracking mechanism in more detail.

A. For PGE's 2019 NVPC forecast, the QF tracking mechanism will operate as follows:

- During 2018:
  - PGE will include in the initial 2019 NVPC forecast all QFs that are expected to achieve COD in 2019 or earlier as identified by the PPA seller.
  - PGE will update its forecast with any known changes through the first November NVPC update.
- During 2019:
  - PGE will track QF CODs to record all actual online dates.
  - PGE will also record any QF CODs not included within the 2019 NVPC forecast.
- During 2020:
  - During Q1 of 2020, PGE will re-run the final 2019 NVPC MONET forecast used to set customer prices, replacing the estimated 2019 QF CODs with the actual CODs recorded during 2019.
  - PGE will record any NVPC difference between the two model runs and place all amounts into a balancing account where they will earn interest at the modified blended treasury rate.[23]
  - PGE will then include any recorded amounts for 2019 into the April 1, 2020 forecast of PGE's 2021 NVPC.

[23] The modified blended treasury rate is the interest rate usually applied on Commission-approved balancing accounts with automatic adjustment clauses that would be similar to the QF tracking mechanism.

Q. Is PGE proposing to adjust for any other differences between forecasted and actual QF contracts?

A. No. PGE is not proposing a true up of power prices, loads, or any variable other than the COD for new QFs.

Q. Does PGE propose to use this method on a going forward basis?

A. Yes. PGE proposes to apply the QF tracking mechanism to each year's NVPC forecast going forward.

I. Forthcoming Updates

Q. Does PGE expect to update any items in future filings in this proceeding?

A. Yes. We expect to update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; historical COB trading data; and make any errata corrections to this initial filing in the April 1 filing. This is standard practice during a GRC proceeding.

IV. Comparison with 2018 NVPC Forecast

Q. Please restate PGE's initial 2019 NVPC forecast.

A. The initial forecast is $375.3 million.

Q. How does this 2019 NVPC forecast compare with the 2018 forecast used to develop NVPC in UE 319 and approved in Commission Order No. 17-384?

A. Based on PGE's final updated MONET run for the 2018 test year, the NVPC forecast was $336.0 million, or $18.31 per MWh. The initial 2019 forecast is $375.3 million, or $20.62 per MWh, which is approximately $2.31 per MWh more than the final forecast for 2018.

Q. What are the primary factors that explain the increase in NVPC forecast for 2019 versus the NVPC forecast for 2018 in UE 319?

A. Table 4 below lists changes in NVPC by factor between 2019 and 2018.

Table 4
Forecast Power Cost Difference 2019 vs. 2018 ($ Million)

Factor	Effect ($M)
Hydro Cost and Performance	$ 19.1
Coal Cost and Performance	10.5
Gas Cost and Performance	(25.8)
Wind Cost and Performance	16.9
Contract and Market Purchases	21.8
Market Purchases for Load Change	(3.7)
Transmission	0.6
Total	**$ 39.3**

* *Numbers may not total due to rounding.*

The primary factors contributing to the increase in NVPC include: 1) a reduction to the federal tax rate, resulting in a reduced gross-up factor used for PTCs; 2) the expiration of PTC generation associated with phase 2 of PGE's Biglow Canyon Wind Farm; 3) the removal of a one-time expiring hydro contract refund that was included in PGE's 2018 NVPC; and 4) an increase in QF contract costs as discussed in Section H above.

Partially offsetting these increasing costs is a decrease to forward gas prices resulting in a reduction to the cost of our gas-fired resources. As we discussed in Section III of our testimony, our load forecast for cost-of-service energy is approximately 2,078 MWa, a decrease of 17 MWa from the 2018 NVPC forecast in PGE’s most recent NVPC proceeding in UE 319.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including net variable power cost forecasting. The Financial Analysis group supports the Power Operations, Corporate Planning, and Rates & Regulatory Affairs groups within PGE.

Q. Ms. Kim, please state your educational background and experience.

A. I received a Bachelor of Commerce degree in Industrial Relations Management from the University of British Columbia. I have been employed at PGE since 2011 in the following positions: Merchant Transmission & Operations Analyst, Real Time Merchant Manager and my current position as Manager of Term and Daily Trading. Before joining PGE, I worked at Puget Sound Energy from 2003 to 2011 as a Power scheduler, Real Time Trader and Supervisor of Day-Ahead and Real Time Trading. Prior to that, I was employed by BC Hydro/Powerex from 1998 to 2003 in various positions including: Human Resources and Recruitment, Power Scheduling to Transmission Management. In my current position, I am responsible for managing the Power Operations Trading group that coordinates the NVPC portfolio over the next five-years.

Q. Mr. Batzler, please describe your qualifications.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

Q. Does this conclude your testimony?

A. Yes.

VI. List of Exhibits

PGE Exhibit	**Description**
301	List of MFRs per Commission Order No. 08-505
302C	February 15 Initial Filing MONET Output Files and Assumptions Summary
303	PGE Western Energy Imbalance Market Addendum: 2019 Scenario

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
   a. Electric curve extract from Trading Floor curve file
   b. Gas curve extract from Trading Floor curve file
   c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
   d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
   e. Oil forward curve
8. Load Inputs. Consists of:
   a. Monthly load forecast from Load Forecast Group
   b. Hourly load forecast from Load Forecast Group
   c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
   a. Capacities
   b. Heat Rates
   c. Variable O&M

      This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
   d. Forced outage rates
   e. Maintenance outage schedules and derations
   f. Minimum capacities
   g. Operating constraints
   h. Minimum up times
   i. Minimum down times
   j. Plant testing requirements
   k. Oil usage volumes
   l. Coal commodity costs
   m. Coal transportation costs
   n. Coal fixed fuel costs classified as NVPC items

      Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

       This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

       For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Exhibit 302C

Protected Information Subject to Protective Order 18-047

PGE Energy Imbalance Market Addendum: 2019 Scenario

January 2018

Energy+Environmental Economics

PGE Energy Imbalance Market Addendum: 2019 Scenario

January 2018

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Prepared For:
Portland General Electric Company

Prepared By:
Jack Moore, Nora Xu, and John Stevens
Energy and Environmental Economics, Inc. (E3)

Table of Contents

Executive Summary

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2019 to model the projected economic benefits of PGE's participation in the Western EIM. As with the 2020 study [1], this study seeks to identify the gross savings potential of PGE's participation in the Western EIM, and does not investigate the initiation, labor, or operating costs associated with EIM participation. The analysis methodology used is consistent with the EIM study that E3 completed for PGE in 2015 (which was based on a 2020 study year).

Similar to the previous EIM study for PGE, this current analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participation in the EIM. The analysis compares PGE's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which PGE does not participate in the EIM.

The BAU simulation case includes operations of a "current EIM", consisting of an updated set of eleven other BAAs assumed to be also participating in

[1] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf)

the EIM in 2019. These EIM participants (other than PGE) are listed in the table below. This 2019 analysis indicates that EIM participation is projected to create $2.8 million in dispatch savings for PGE (compared to a BAU case in which PGE does not participate).

Including the impact of pooling flexible reserves, PGE total EIM savings are $4.5 million. This $4.5 million total EIM savings for PGE are $1.7 million greater than the EIM savings in the base case without pooling, indicating that in this scenario reduced PGE reserve requirements due to diversity pooling yield additional dispatch flexibility and additional EIM savings.

Table 1: BAA Participants in EIM in 2019 BAU Case

Current EIM participants for BAU Case[2]
Arizona Public Service (APS)
Powerex (BCTC)
CAISO
Idaho Power Company (IPC)
Los Angeles Department of Water and Power (LDWP)
NV Energy (NVE)
PacifiCorp East (PACE)
PacifiCorp West (PACW)
Puget Sound Energy (PSE)
Sacramento Municipal Utility District (SMUD)
Seattle City Light (SCL)

[2] In this 2019 Scenario, SCL, LADWP and SMUD are assumed to join the EIM in April 2019. After completing the 2019 Scenario, SCL announced that its expected entry would be in 2020 instead of 2019.

1 Study Assumptions and Approach

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2019 to model potential economic benefits of PGE's participation in the Western EIM. As with E3's 2015 EIM study for PGE, which focused on the 2020 study year, this study seeks to identify the savings potential of PGE's participation in the Western EIM.

1.1 Input Data Changes

The PGE EIM 2020 study base case database was used as the starting point dataset used for this updated 2019 analysis. That 2020 study database was updated to reflect differences in the expected topology and operating conditions in 2019 versus 2020. The updates for this 2019 analysis are described in more detail below, and are summarized in Table 2. The updated real time transfer capability is shown in Figure 1.

+ **Topology updates.** To reflect PGE's anticipated transmission transfer capabilities for the year 2019, E3 updated transfer limits on three zonal connections in the model: the path between CAISO and PGE, between the Bonneville Power Administration (BPA) and PGE, and the path between PacifiCorp

West (PACW) and PGE. [3] In addition, this update implements a choice by PGE to hold a portion of the transmission capacity from PACW to PGE unscheduled in the DA and HA stages, which enables more opportunities for PGE to import from the EIM in real time and results in an increased savings of approximately $0.5 million.

+ **Wheeling Rates.** E3 updated day-ahead wheeling rates for the BPA to PGE, PACW to PGE and CAISO to PGE lines using data from PGE to reflect current transmission tariffs and rate schedules.

+ **Gas prices.** Gas prices for 2019 were updated based on monthly projected hub prices from Wood Mackenzie as of September 2017. Consistent with the methodology in the 2020 report, gas hub prices are translated to BA- and plant-specific burner tip prices using estimated zone-specific delivery charges developed for the NWPP EIM Study.[4] These prices are lower than the 2016 Wood Mackenzie gas price projections used for PGE's EIM 2018 study.

+ **Generation updates.** At PGE's direction, E3 updated several thermal plants in PGE's generation fleet to reflect their status in 2019. E3 continued to include the Boardman Plant, scheduled to cease coal-fired operations by year-end 2020, in their analysis.

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[3] Compared to the 2018 study base case, CAISO to PGE transfer capability was increased from 600 MW to 627; PACW to PGE transfer capability was increased from 276 MW to 295 MW and PGE to PACW transfer capability was increased from 306 MW to 320 MW. 2018 transfer capabilities can be found in E3's 2018 Energy Imbalance Market Addendum. Compared to the original 2020 study base case, BPA to PGE transfer capability was updated from 4,093 MW to a seasonally varying limit of 4,403 MW from January to April and from November to December, and a limit of 3,760 MW at all other times; PGE to BPA transfer capability was updated from 4,093 MW to a seasonally varying limit of 4,403 MW from January to April and from November to December, and a limit of 3,760 MW at all other times. Original 2020 transfer capabilities can be found in E3's 2015 PGE EIM Comparative Study.

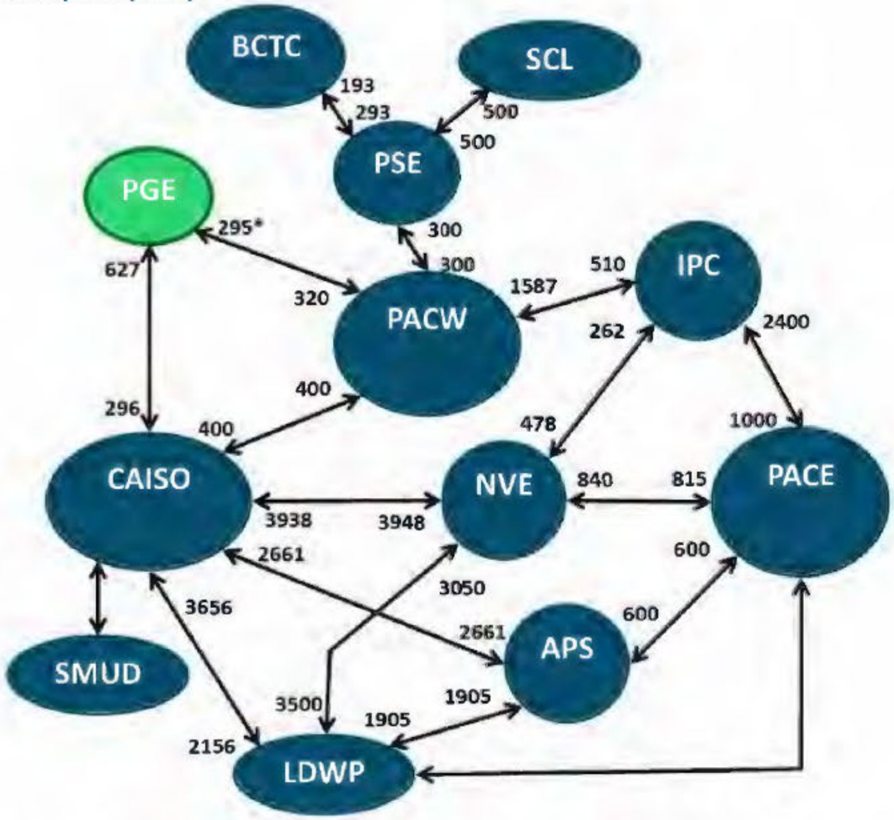
[4] The NWPP EIM study was published in October 2013 and is accessible at: http://www.nwpp.org/documents/MC-Public/NWPP_EIM_Final_Report_10_18_2013.pdf

E3 used data from PGE to update operating characteristics of the Colstrip, Boardman, Carty, Coyote Springs, Beaver and the Port Westward Plants. Included in these updates were start-up costs, variable O&M charges, outage dates, monthly maximum capacities, maximum ramp up and down, minimum down time, heat rate, maximum capacity, and minimum stable level. At PGE's request, E3 also updated capacities, ramping rates, monthly energy budgets, monthly maximum power ratings and minimum stable levels for the hydropower plants in the PGE BAA. E3 also added Portland Hydro Project as a fixed dispatch hydropower generator to the model.

+ **Renewable generation updates.** E3 scaled renewable generation in the Western Interconnection by BAA to match to data available for units in WECC TEPPC 2026 and expected to be online by 2019. E3 cross-referenced this data with renewable generation reports in EIM participants' integrated resource plans (IRP) when possible. In California, the resource mix was updated to reflect currently projected renewable generation levels for 2019 based on CAISO and CEC data. As with the 2020 database, estimates of rooftop PV are included in CAISO solar. PGE provided updates for its forecasted levels of wind generation for 2019.

+ **Load updates.** Loads were updated for each BAA by scaling monthly energy to 2019 forecasted levels reported in the WECC Load and Resources (LAR) submittals by Western BAAs, with the exceptions of PGE and CAISO. PGE load was scaled to monthly energy totals provided by PGE. In CAISO, load was scaled to California Energy Commission's (CEC) monthly forecasts created as for its Integrated Energy Policy Report (IEPR).[5] Overall, WECC load forecasts have been reduced in the 2019 case compared to the 2020 database, both due to earlier model year and the more updated load forecast which reflects lower forecasted WECC load growth.

Figure 1. Real-time Transfer Capabilities across the Western EIM with PGE Footprint (MW)



* PACW to PGE Transfer limited to 19 MW in DA and HA markets

[5] CEC, California Energy Demand Updated Forecast, 2017-2027. See: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215745_20170202T125433_FINAL_California_Energy_Demand_Updated_Forecast_20172027.pdf.

Table 2. Summary of Input Data Modification between the 2019 and 2018 EIM Study

	PGE Portfolio		EIM Members Portfolio and WECC Portfolio	
Scenario year	**2019**	**2018**	**2019**	**2018**
Load	Provided by PGE; 0.45% reduction of annual load from 2018.	Provided by PGE; 14.4% reduction on average from 2020 to reflect 2018 and newer data	Scaled for 2019 to WECC Load and Resource data based on submittals by BA; annual 2019 WECC-wide load is 1.1% lower than 2018 annual load.	Scaled for 2018 to WECC Load and Resource data based on submittals by BA; generally lower than 2020 data
Gas Price	PGE September 2017 projection of 2019 monthly forward prices for Western hubs	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE September 2017 projection of 2019 monthly forward prices for Western hubs	PGE August 2016 projection of 2018 monthly forward prices for Western hubs
Generation	Boardman plant online; operational characteristic updates for thermal and hydro plants; Portland Hydro project added.	Boardman plant online	–	–
	Wind portfolio is 717 MW	Wind Portfolio is 717 MW	EIM participants' wind and solar scaled to best information from IRPs and TEPPC 2026 Common Case generator list; CA updates from E3 & CEC solar projections	EIM participants' wind and solar scaled to best information from IRPs and TEPPC 2026 Common Case generator list; CA updates from E3 & CEC solar projections
	PGE Wells operates for entire year	PGE Wells' contracted output included Jan. – Aug.	--	AVA, PACW, PSE contracted output included Jan. – Aug.
	Colstrip units 3 and 4 not dispatchable in real time	Colstrip units 3 and 4 not dispatchable in real time	EIM participants' shares of Colstrip 1-4 not dispatchable in real time	EIM participants' shares of Colstrip 1-4 not dispatchable in real time
Transmission	Max transfer from PacifiCorp West (PACW) to PGE is 295MW/320MW into/out of PGE; PACW into PGE transfer limited to 19 MW in DA/HA market	Max transfer from PGE to PACW updated to 306 MW; max transfer from PACW to PGE updated to 275 MW	EIM connections added to Sacramento Municipal Utility District (SMUD), Seattle City Light (SCL), Los Angeles Department of Water and Power (LDWP) and Powerex.	EIM connections added to Idaho Power Company and Arizona Public Service
	Max transfer from PGE to BPA is 3760/4403MW in both directions for May-October and rest of year respectively; max transfer from CAISO to PGE is 627MW/296MW into/out of PGE	Max transfer from COB into PGE updated to 600MW; max transfer from PGE into COB remains 296 MW	–	–
Other EIM Participants	–	–	Arizona Public Service (APS), Powerex, California ISO, Idaho Power Company (IPC), Los Angeles Department of Water and Power (LDWP), NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE), Sacramento Municipal Utility District (SMUD), Seattle City Light (SCL)	APS, California ISO, IPC, NVE, PACW, PACE, PSE

2 EIM Benefit Results

2.1 Benefits to PGE

Table 3 below summarizes the simulated annual benefits to PGE from participation in the EIM in 2019. The first column represents the incremental dispatch cost savings to PGE from participation in the EIM and assumes no cost savings from flexible reserve pooling, while the second column reports the incremental benefit to PGE (beyond the savings reported in the first column) from flexible reserve pooling. The third column reports the sum of the first two columns and represents the total EIM savings for PGE, including the impact of flexible reserve pooling.

Flexible reserve pooling uses lower reserve requirements to reflect the diversity in load shapes and solar and wind resources across the expanded EIM footprint, including PGE. Monthly diversity factors are produced that reflect PGE's net load contribution to the EIM's monthly average requirements; diversity factors are applied to BA-specific reserve requirements, which are individually calculated. The impact to PGE from pooling flexibility reserves with the rest of the EIM is valued by the increase in benefits in the flexible reserves pooling case versus the dispatch cost savings only case.

Savings are calculated as the reduction in cost compared to a common BAU case in which PGE does not participate in the EIM. In the day-ahead and hour-ahead scenarios, net imports into and out of PGE are valued at the average of the PGE and BPA zones' energy prices. In the real-time stages, net imports for EIM participants are instead valued at an average EIM price. Overall, the dispatch cost savings are $2.8 million in the base scenario. Including the incremental savings of $1.7 million from pooling flexible reserves, PGE total EIM savings are $4.5 million.

Table 3. Annual Benefits to PGE by Scenario, Western EIM (2015$ million)

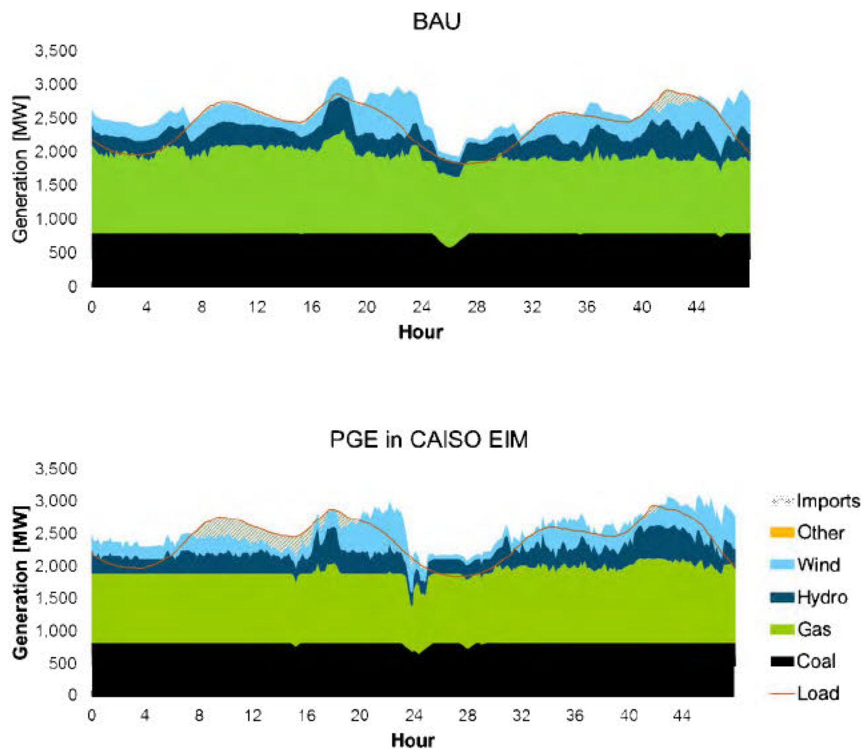
Scenario	Dispatch cost savings to PGE	Additional impact from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$2.8	$1.7	$4.5

2.2 Western EIM Results Discussion

Over the course of the 2019 simulation year, PGE has more imports than exports in real time, and thus is a net EIM importer for this study. PGE's benefits result is similar to the cost-saving opportunities that were observed for PGE in the 2020 EIM analysis (completed in 2015) and the updated analysis for a 2018 EIM study year (completed in 2016). PGE realizes savings both by (a) importing from the EIM to avoid production cost on higher heat rate internal generation during intervals when EIM prices are low, as well as (b) by exporting to the EIM, earning net revenues when EIM prices are higher than PGE's internal cost.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over December 12-13, 2019. The upper chart shows PGE's dispatch in the BAU scenario, while the lower chart shows how that dispatch changes with PGE in the EIM.

Figure 2. PGE Real-Time Dispatchable Generation, Western EIM, December 12-13, 2019



Over this two-day period, PGE both imports from and exports energy to neighboring BAAs who are EIM participants.[6] EIM participation enables greater transactional flexibility. On December 12th, EIM participation results in PGE reducing its generation cost relative to the BAU Case by backing down its gas-fired generation and Boardman, with the majority of the generation reduction coming from the PW2 and Beaver units. PGE increases its real-time energy imports from the EIM in order to back down its internal generators. On December 13th, EIM participation instead results in PGE ramping up generation to earn revenues from increased exports to the rest of the EIM. The majority of the additional PGE generation that enables EIM exports on this day occurs on PW2 and Boardman.

[6] In Figure 2, imports are identified as the grey area which occurs in intervals where the red line (representing load) exceeds the stacked sum of PGE generation. Exports occur in intervals when the sum of PGE's generation exceeds the load line.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Anne Mersereau
Tamara Neitzke

February 15, 2018

I. Table of Contents

II. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity & Inclusion. My responsibilities include establishing total compensation policies and employee policies, continuing to strengthen the work culture at PGE, managing employee recruitment, development and retention, managing employee relations, and overseeing safety, corporate resiliency, worker's compensation, and health programs.

My name is Tamara Neitzke. I am the Director of Compensation and Benefits in the Human Resources Department.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains PGE's key talent management challenges. In particular, we describe how PGE's compensation philosophy is designed to address our compensation challenges, and we present total compensation costs for the 2019 test year. Total compensation costs include base wages and salaries, incentive pay, and employee benefits.

Q. What are PGE's expected total compensation costs and the cost drivers in 2019?

A. PGE forecasts approximately $395.1 million in total compensation costs for 2019. Table 1 below summarizes the cost and compensation components of the 2017 actuals, 2018 budget, and 2019 test year. Our 2018 budget was based on the results of our 2018 general rate case as filed in Docket No. UE 319 (UE 319).

Table 1
Estimated Total Compensation Costs ($Millions)

Component	**2017 Actuals**	**2018 Budget**	**2019 Test Year**	**2017-2019 Delta**
Wages & Salaries	$260.7	$275.1	$281.5	$20.9
Incentives	$28.2	$30.6	$13.0	($15.2)
Benefits	$82.3	$96.5	$100.5	$18.2
Total Compensation*	**$371.2**	**$402.1**	**$395.1**	**$23.9**

* Numbers may not sum due to rounding.

The net difference between 2017 actuals and forecast 2019 test year costs is an increase of $23.9 million. Looking at the component parts, $20.9 million of the increase is from forecasted wages and salaries due to market-driven salary adjustments and increasing labor required to meet PGE's business, regulatory, and customer related goals. Most of this increase occurs between 2017 and 2018 and was discussed in UE 319. We further explain the changes in more detail in Section III below. Additionally, Section III discusses PGE's wages and salaries in aggregate (i.e., both expense and capital related full-time equivalent employee costs in the reported wages and salaries).

A primary driver of benefits costs from 2017 to 2019 is the continued increases in health and wellness costs ($12.8 million), most of which occur between 2017 and 2018. The total compensation increases are partially offset by a decrease in PGE's incentive request, which represents a reduction of approximately $15.2 million from 2017 actuals.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: PGE's Total Compensation Philosophy and its Challenges;
- Section III: Wages and Salaries;
- Section IV: Incentives;

- Section V: Benefits; and
- Section VI: Summary and Qualifications.

III. PGE's Total Compensation Philosophy and its Challenges

Q. Please briefly describe PGE's philosophy on total compensation.

A. PGE's philosophy is to provide total compensation sufficient to attract and retain employees with strong qualifications and skills necessary to provide safe, reliable, affordable, cleaner, and more secure energy to our customers. To keep costs reasonable, PGE actively controls costs by targeting market median conditions for our compensation program.

Q. What are the components of PGE's total compensation?

A. PGE's compensation components include:

- Wages and Salaries: PGE designs its non-union and union wages to target the market median based on company size, geographic market, and job function.
- Incentive Pay: PGE designs its incentive pay to attract, retain, and reward employees for achieving performance goals that help PGE achieve its objectives.
- Benefits: PGE provides market-aligned health and welfare benefits. PGE also provides a pension and a 401(k) plan for retirement.[1] PGE strives to maintain a benefits package that meets our employees' needs and balances the features and costs both among employee groups and against what other employers in our market provide to their employees.

Q. What are the major challenges for PGE's talent acquisition and compensation?

A. PGE is facing four strategic talent acquisition[2] challenges that affect our workforce and compensation philosophy:

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[1] PGE's pension plan is closed to all new employees. Effective February 1, 2009, new non-bargaining employees were ineligible for the pension plan. Effective January 1, 2012, new bargaining unit employees at Coyote Springs and Port Westward work sites were ineligible for the pension plan. PGE had previously closed the plan to all other new bargaining unit employees effective January 1, 1999.

[2] Talent acquisition is also called "recruiting" in this testimony.

1. The need to recruit well-qualified, skilled employees in a competitive marketplace;
2. Developing the pipeline of talent to ensure continuity and improvement in the services we provide despite a large number of employee retirements;
3. Ensuring that our workforce reflects the diversity of our service area; and
4. Managing and controlling our health care costs while providing benefits that attract and retain the well-qualified, skilled employees PGE needs.

A. Talent Acquisition

Q. Please describe the first challenge – hiring well-qualified, skilled employees in a competitive marketplace.

A. Our customers' needs and expectations are evolving in a manner that requires PGE to improve the technical skillsets and versatility of our employees. While we generally observe a need for new and different skillsets throughout PGE, examples of how these skillsets are evolving include:

- Utilities are implementing new technologies and experiencing fast-paced changes in methods for reliably operating the electric grid with higher levels of variable energy resources. These technologies and changes require utility personnel, such as power plant technicians and substation operators, to possess broader, more versatile skills.[3]
- Senior managers have traditionally possessed deep subject matter expertise built through decades of experience. PGE is increasingly placing a greater emphasis on candidates with strong managerial abilities along with technical abilities,

[3] Including advanced technical, mathematical, and mechanical concepts.

leading PGE to compete for such managerial talent with both utility and non-utility industries.

- Increasingly complex and integrated systems throughout PGE and increasing need in the areas of cyber and physical security require highly skilled and specialized Information Technology (IT) professionals, who are in demand both within and outside of the utility industry.
- Diversity in our customer base has led us to staff customer contact centers with a broader set of language skills (e.g., Spanish and Russian fluency). Employee candidates with the needed language skills are difficult to attract and retain without offering premium compensation relative to PGE's market benchmarks.

Our recruiting challenges for these necessary skills continue to be most acute for several specialties.[4] We have described some similar recruiting challenges in our past rate case filings, and the competition has only increased. As the economy reaches full employment, regionally and nationally, potential employees can afford to be more selective about changing jobs or moving. For positions such as line workers,[5] we find that we must more frequently recruit individuals who require relocation. Also, in this type of recruiting environment, we sometimes find it necessary to pay higher compensation for specific positions that are difficult to fill and to cover relocation costs.[6]

Q. How does PGE approach this recruiting challenge?

A. We approach this challenge in three ways:

[4] Specialties include (1) senior managers in all areas, (2) engineering, (3) IT security, development, and project management, (4) senior professionals working with data, (5) energy trading and pricing, and (6) skilled trade positions such as power plant control operators, meter-service technicians, and line workers.

[5] Tradesperson who constructs and maintains electric transmission and distribution lines.

[6] PGE periodically evaluates the market-alignment (i.e., the maintaining of total compensation that is competitive in the market) of its total compensation program both in order to retain employees and to attract external talent.

1. We focus on developing talent internally wherever reasonably possible, for example, by using cross-training opportunities to temporarily fill some senior level or other hard-to-fill positions. The cross training provides employees an opportunity to work in a different position, and provides management an opportunity to evaluate their potential.
2. We sometimes find it necessary to externally recruit senior level talent to find individuals with the qualifications and skills required for the position. Recent examples include positions in PGE's IT and Power Operations. When PGE does recruit senior level talent externally, we may involve external recruiters, and we may be required to pay premium wages and relocation costs for these hard-to-fill positions.
3. We engage in proactive hiring strategies through job fair and college campus outreach, online tools and research, and database management.

In addition, PGE uses an employee referral program to increase the number of qualified applicants for select PGE positions.[7] This program provides incentives to current PGE employees for referring qualified external candidates. As discussed in PGE Exhibit 500, PGE is also adding Human Resources employees in 2018 and increasing its budget for outside services to assist with the heavy recruitment process.

B. Development

Q. Please describe the second challenge – the development pipeline.

A. Ultimately, our challenge of recruiting well-qualified, skilled employees is closely related to our second challenge (i.e., the need to develop and improve talent to help PGE meet

[7] Examples of select PGE positions include journeyman lineman, supervisory control and data acquisition (SCADA) engineers, and IT professionals.

customers' needs). This is important because a significant portion of our work force is likely to leave PGE soon. While the average age of PGE's employees has stabilized, approximately one-third of them are retirement eligible. PGE is trying to minimize the knowledge and skill loss that occur when highly-skilled and long-tenured employees retire.

Q. What is PGE's approach to the development challenge?

A. PGE supports employee development through educational assistance, mentoring, and cross-training opportunities. We provide an extensive program of formal and informal training classes to help develop our employees in both subject matter expertise and managerial skills, and provide access to outside training where it is cost-effective. In addition to these programs, PGE uses the following work force planning strategies:

- Strengthening our summer hire program that helps to develop entry-level engineering, business, and other professional candidates.
- Strengthening manager capabilities to identify key growth and development areas for their employees and supporting that development.
- Creating positions that allow high potential employees to rotate through key development roles throughout PGE.
- Focusing efforts on succession planning, including the identification of tailored methods to recruit candidates with the particular skill sets to fill succession needs.

C. Diverse Workforce

Q. Please describe the third challenge – ensuring a diverse workforce.

A. PGE is committed to employing a workforce that is representative of the communities we serve. A diverse workforce helps PGE recognize and respond more efficiently to the diverse needs of our communities. Diversity and inclusion are one of PGE's Core Values.[8] PGE believes, and this is borne out by research studies, that employee diversity and inclusion has multiple business benefits, including higher levels of employee engagement, more effective customer engagement, and improved safety performance.[9] The safety benefits come from employees' feeling a greater sense of inclusion, which encourages them to take more ownership for acting in a safe manner and to speak up when they see something unsafe.

PGE's service area grows more diverse each year, and while our workforce diversity has improved, we continue to face challenges in attracting well-qualified and skilled employees who match the demographics of our communities, particularly in senior-level management and the trades.[10] In our efforts to attract a diverse workforce, we experience heightened competition because all industries in our service area are also striving to improve the diversity of their respective workforces.

Q. What is PGE's approach to its diversity challenge?

A. PGE first works to create compelling compensation programs and a work culture that attracts talent across the demographic spectrum. Beyond ensuring competitive compensation design, attracting and retaining a diverse group of employees must be supported by creating an inclusive work environment. Potential and current employees look for concrete visible examples of our continuing commitment to diversity and inclusion. In 2017, these examples include:

- Sponsored and participated in Oregon Tradeswomen Inc.'s annual career fair to

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[8] PGE's Core Values are: Safety & Health; Continuous Improvement; Ethical Business Practices; Diversity & Inclusion; Community Investment; and Environmental Stewardship.
[9] A copy of PGE's Business Case for Diversity is included in our work papers.
[10] Trades positions include skilled labor jobs such as lineman and wireman, which require specific and specialized training.

bring awareness of trade occupations to women of all ages;

- Sponsored a professional networking event of over 700 professionals at the Oregon Museum of Science and Industry in conjunction with Partners in Diversity that included the recognition and welcoming of 40 new diverse professionals of color to the greater Portland area;
- Received a top score of 100% rating on the Human Rights Campaign's Corporate Equality Index for the fifth consecutive year; and
- Planning and promotion of the 2018 PGE Diversity Summit Conference, scheduled for May 2018, at the Oregon Convention Center for approximately 1,500 attendees. This is the seventh time PGE has sponsored and conducted this regional resource event, which we expect to sell out again. PGE offers this professional development event to the public and private sectors to discuss how diversity drives innovation and business success.

PGE has also collaborated with Emerging Leaders Internship (ELI) to expand the diversity pool of our summer hire program and we are placing a greater emphasis and focus on diversity with the Multiple Engineering Cooperative Program (MECOP), the Civil Engineering Cooperative Program (CECOP), and our Pre-Apprentice Program. Internships are one entry point to PGE and by focusing on the diversity of this and similar entry-points, PGE is better able to develop a workforce that is representative of the communities we serve. We found internships to be successful in 2017 and we plan to increase our efforts in targeting positions for internships with ELI in 2018 and 2019.

D. Health Care

Q. Please describe the fourth challenge – health care costs.

A. Health care benefits have traditionally been a key element of the total compensation program PGE uses to attract well-qualified and skilled employees. Health care costs continue to rise faster than overall wages. In response to rising health care costs, PGE has implemented creative health care benefit designs.

Q. What is PGE's approach to the health care cost challenge?

A. Our changes to health care benefit designs effectively balance cost and risk for both PGE and employees, positioning PGE to attract employees in a cost-effective manner for customers. Recent changes in the health care market have increased the focus on the role of the consumer and behavioral design. Consumerism and behavioral design encourage choice in health care options and more readily allow individuals to make decisions regarding quality and cost of health care in a manner similar to other goods. PGE has embraced these trends by focusing on consumerism in health care insurance plans and improving our wellness offerings. We discuss these changes in more detail in Section V below.

IV. Wages & Salaries

Q. What are the major components of PGE's total wage and salary costs?

A. Total wages and salaries are comprised of the number of full-time equivalent employees (FTEs) and the market-based pay structure.

A. Full-Time Equivalent Employees

Q. Please describe how PGE determines the first component, the number of FTEs required for the test year.

A. As part of the annual budgeting process, managers determine the number of labor hours in each position type that are expected to be required to accomplish their departments' work for the coming year. PGE then converts the total labor hours into FTEs by dividing total labor hours by the number of available work hours during the year. For example, an employee hired mid-year would be budgeted as one-half (or 0.5) FTE. For historical periods, FTEs reflect the actual number of hours worked divided by the number of work hours during that year.[11] Table 2 and Table 3 provide PGE's actual total FTEs (excluding overtime) for 2017, FTE budget for 2018, and FTEs forecast for 2019, separated by division and by employee class. Additional detail can be found in PGE Exhibit 401.

Table 2
Full-Time Equivalents by Division

PGE FTEs (straight time)	2017 Actuals	2018 Budget	2019 Test Year*	2017-2019 Delta
Administrative and General (A&G)	372.1	402.9	389.4	17.2
Information Technology	304.3	332.8	306.7	2.4
Customer Service/Accounts	464.5	451.9	455.1	-9.4
Generation	548.7	558.8	562.2	13.5
Transmission & Distribution (T&D)	1,044.9	1,153.0	1,154.1	109.2
Total FTEs**	**2,734.6**	**2,899.4**	**2,867.5**	**132.9**

**2019 FTEs are net of PGE's pre-filing adjustments.*
***Numbers may not sum due to rounding.*

[11] All hours over 2080 per position, per year are excluded.

Table 3
Full-Time Equivalents by Class

PGE FTEs (straight time)	2017 Actuals	2018 Budget	2019 Test Year*	2017-2019 Delta
Exempt	1,502.9	1,632.4	1,592.7	89.9
Hourly	474.5	469.8	477.5	3.0
Officer	12.3	12.0	12.0	(0.3)
Union	744.9	785.2	785.2	40.3
Total FTEs**	**2,734.6**	**2,899.4**	**2,867.5**	**132.9**

**2019 FTEs are net of PGE's pre-filing adjustments.*
***Numbers may not sum due to rounding.*

Q. Will PGE require additional employees in 2018 and 2019?

A. Yes. While PGE made significant progress in hiring during 2017, from an FTE perspective, we still require 132.9 additional FTEs, the majority of which we expect to hire in 2018. As discussed below, our increasing FTE requirements occur primarily from 2017 to 2018 and are due to the demands discussed in UE 319.

Q. What areas require these additional FTEs?

A. Table 4 below provides a brief description of the change in FTEs and, where applicable, work these employees will be required to perform, with a reference to a more detailed explanation in PGE's filing.

Table 4
Change in FTEs from 2017-2019

Area	Change in FTEs	Explanation	Reference
A&G	17.2	Security, training, talent acquisition support	Exhibit 500
IT	2.4	Information security	Exhibit 600
Cust Svc/Accts	-9.4	CET reductions	Exhibit 900
Generation	13.5	Resource planning, power supply engineering	Exhibit 700
T&D	109.2	System reliability, increasing customer work	Exhibit 800

Q. What are the primary drivers leading to PGE's projected FTE requirements?

A. The additional FTEs required for 2018 and 2019 are largely driven by the same requirements identified in UE 319. The main drivers continue to be increasing regulatory requirements, new security requirements, increasing customer growth, and capital work that PGE expects to staff with employees, as opposed to contractors. While PGE still faces recruiting and hiring challenges for specialized positions, we expect to fill the majority of our FTE requirements in 2018, consistent with expectations in UE 319.

Q. PGE increased the hiring of FTEs beginning in late 2016 to meet its growing requirements. What progress has PGE made?

A. PGE has made significant progress in hiring additional FTEs beyond PGE's regular turnover and seasonal hiring requirements in spite of a tight labor market that has increased overall turnover at the company and increased competition for skilled trade workers in particular. We have hired, or are in the process of hiring, one-fifth of the 132.9 incremental FTEs previously described. We expect to hire the majority of our remaining incremental need during 2018. Table 5 below, shows PGE's hiring progression, beginning with 2016 actuals. Table 5 also shows posted requisitions (i.e., employees we plan to hire soon), and a projection of the remaining employees we expect to hire in 2018 and 2019.

Table 5
FTE Hiring Activity

PGE FTEs (straight time)	2016 Actuals	(+) 2017 Incremental FTEs	(+) New hires through Jan. 2018	(+) Requisitions in Process through Jan. 2018	(+) Additional 2018-2019 FTEs	= 2019 Test Year*
A&G	367.3	4.9	3.0	4.5	9.7	389.4
IT	272.4	31.9	-	2.0	0.4	306.7
Customer Service/Accounts	448.2	16.3	-	-	(9.4)	455.1
Generation	535.7	13.0	1.0	2.0	10.5	562.2
T&D	957.7	87.2	2.0	14.0	93.2	1,154.1
Total FTEs	**2,581.3**	**153.3**	**6.0**	**20.5**	**106.4**	**2,867.5**

**2019 FTEs are net of PGE's pre-filing adjustments, and numbers may not sum due to rounding.*

B. Market-Based Pay Structure

Q. Please describe how PGE determines its market-based pay structure.

A. PGE periodically compares its wages and salaries to the relevant markets. To do this, we collect a wide variety of compensation studies from various organizations and experts. These data are then used to benchmark the salary ranges of various positions against similar

PGE positions. PGE performs regression analyses using these data to determine the mid-point for each position classification. In general, actual salaries for each position level must fall within a specific range of PGE's pay structure as determined by these mid-points and the range around the mid-point. However, as described in Section II above, we sometimes find it necessary for PGE to pay premium wages for hard-to-fill positions within the category.

Recognizing that each company can be in a different position regarding workforce age and experience, we compare salary range mid-points rather than salaries paid. This provides a more accurate comparison of salary structures. The actual salary level within a range is dependent on several factors, including performance and experience. The consistent use of this practice ensures that our current and prospective employees are fairly compensated while controlling costs.

Q. What has been the recent trend for overall wages and salaries in the marketplace?

A. Wages and salaries nationally and more specifically in Oregon have been rising at a higher rate in 2017 and are forecast to continue increasing at rates higher than we've seen for a number of years. The December 2017 Oregon Economic and Revenue forecast[12] indicates that job openings for higher paying jobs are at all-time highs and that wages (along with other benefits) continue to rise. The December report forecasts the annual increase to the average wage rate for Oregon at 4.5% for 2018 and 4.1% for 2019.

[12] http://www.oregon.gov/das/OEA/Documents/forecast1217.pdf.

Q. Have you performed any recent comparisons of PGE's wage structure with the market?

A. Yes. In 2017, we compared our hourly non-union and salaried non-officer positions with the market. Our study showed that PGE's wage and salary structure was aligned with the market, indicating that PGE's wage and salary structure was well-designed and market-based. The details of this study are provided in our confidential work papers.

Q. What is PGE's 2019 test year forecast for wages and salaries?

A. Table 6 below summarizes total wage and salary costs for 2017, 2018, and 2019 by division.

Table 6
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time)	2017 Actuals	2018 Budget*	2019 Test Year*
Administrative and General	$73,980	$79,464	$77,984
Customer Accounts	$26,678	$25,548	$26,881
Customer Service	$7,240	$8,309	$8,609
Generation	$54,307	$54,192	$56,639
Transmission & Distribution	$98,485	$107,560	$111,427
Total Wages & Salaries**	**$260,689**	**$275,074**	**$281,540**

**2018 & 2019 amounts are net of PGE's pre-filing adjustments.*
***Numbers may not sum due to rounding.*

Based on industry and overall labor market data, PGE used a rate of 3.5% to escalate its non-bargaining wages and salaries for 2018 and 4.0% to escalate non-bargaining wages and salaries for 2019. These rates are lower than the above-referenced Oregon average wage forecast of 4.5% for 2018 and 4.1% for 2019. Similarly, for union wages and salaries, PGE applied a rate of 2.5% for 2018 and 3.0% for 2019.

Q. Please identify the bargaining unit contracts in effect with the IBEW Local No. 125 (IBEW).

A. There are two collective bargaining agreements (CBAs), one for each bargaining unit. The largest bargaining unit (i.e., the majority of PGE's union employees) covers all union employees at work sites other than Coyote, Port Westward, and Carty. A second bargaining unit covers employees at Coyote, Port Westward, and Carty. We reflect the costs for both active CBAs in our forecast of wages and salaries for the 2019 test year.

Q. Please briefly describe how total compensation, including wages, is determined for IBEW employees.

A. Total compensation, including wages, is the result of arm's length,[13] collective bargaining between PGE and the IBEW. Under collective bargaining, wages, other parts of total compensation, and other conditions are negotiated as a whole (i.e., changes to wages and other parts of compensation are considered alongside other contract provisions like work rules and schedules). Thus, the bargaining agreements in their entirety reflect the negotiated outcomes that both parties support.

Q. Has PGE made any adjustments to its FTEs and wages and salaries for 2019?

A. Yes. To account for vacancies and/or unfilled positions, PGE has included a $10 million O&M reduction to its base budget wages and salaries forecast. The adjustment for vacancies and/or unfilled positions translates into a 99.9 overall FTE reduction.

C. Labor Budgeting

Q. Is there a different way to budget labor resources?

A. Yes. PGE is deliberating on the way we budget our labor resources. Changes to the utility business model require a more flexible mix of employees. For example, changes in software development strategies may require a change from a large group of lower-wage developers to a smaller group of highly skilled (and highly paid) senior architects. Other areas of the business may, due to talent development needs or changing technology, require a larger number of early career employees rather than smaller number of more highly paid senior

[13] In an arm's length negotiation, each party is acting independently, and in their own self-interest.

employees. What this suggests is that managers should focus on labor costs rather than FTEs to address such issues.

Q. How does focusing on labor dollars, rather than FTEs, improve PGE's labor budgeting?

A. By holding managers to a labor budget irrespective of FTEs, they can focus on hiring the right mix of employees and not be constrained by FTE count. Labor dollar metrics allow managers to change their workforce composition, including skillset mixes and contractor expertise, to respond to changes in technology and competitive requirements. Focusing on labor dollars also allows for improved tracking of labor resources when functional distinctions are blurred (such as the distinction between operational technology and information technology).

Q. Has PGE made any changes to its budgeting process for the 2019 test year?

A. No. We developed our FTE requirements using the process described at the beginning of this section. However, as the utility business model continues to evolve and the pace of change continues to accelerate, we are considering other ways to adapt more quickly to changes and become more flexible in order to ensure we have the right mix of talent. A focus on labor dollar metrics, as opposed to FTEs, is consistent with most other elements of PGE's regulatory accountability for operating expenses. Similar to non-labor expenses, any proposed increases to customer prices related to labor dollars are subject to scrutiny of output efficiency and justification.

Q. Would any future labor budgeting changes also involve changes to the inputs used in determining market reference pay points?

A. No. PGE would continue to use well-established industry and function-based national, regional and local benchmarks to determine market-based pay points for non-bargaining employees.

V. Incentives

Q. What is incentive pay?

A. Incentive pay is part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on pre-established performance goals and some additional rewards for extraordinary achievement. Most incentive pay places a portion of employee pay at risk, making it dependent on the employee's performance and quality of output, along with PGE's overall performance. While incentive pay shares characteristics in common with bonuses, most of PGE's incentive pay is different from a bonus because of the "at risk" component.

Q. What is PGE's strategy for incentive compensation?

A. As with wages and salaries, PGE's strategy is to provide incentive pay that attracts, retains, and motivates employees. The incentive goals for all participants stem from PGE's corporate scorecard goals, which support our strategic direction and our commitment to core principles, such as delivering exceptional customer experiences and pursuing excellence in our work.

Q. How does PGE determine the structure and target percentages for incentives?

A. PGE monitors the employment market and acquires information regarding incentive compensation program design practices. Then, consistent with our total compensation program design, PGE's incentive targets are set at the 50^{th} percentile, or middle of the market. Even though it is a small percentage of PGE's total compensation, incentive pay is very important; it assists PGE in attracting and retaining well-qualified and skilled employees and encourages high level employee performance and productivity. High performing employees benefit the company and customers when they are working efficiently and effectively and are engaged in their work. PGE's incentive programs also align employee scorecard goals with shared customer and company goals that strive to keep costs low, improve customer satisfaction, and maintain PGE's financial stability.

Q. What percentage of PGE's total compensation are incentives?

A. Incentive pay is approximately 7.5% of PGE's 2019 total compensation costs. However, because PGE has made a pre-filing adjustment to our incentives request for this filing, the amount of incentive pay in our request represents approximately 3.3% of PGE's 2019 total compensation. Our pre-filing adjustment removes 100% of the Officer Long-Term Incentive Program costs and 50% of the cost of all other incentives plans. Table 7 below summarizes PGE's actual incentive costs for 2017 and 2018, and our request for 2019. We discuss the four categories of incentive plans in subsections A through C below.

Table 7
Total Incentives ($000)

Incentive Plans	**2017 Actuals**	**2018 Budget**	**2019 Test Year***
Performance Incentive Compensation	$12,962	$14,642	$7,680
Annual Cash Incentive	$7,379	$6,940	$3,440
Stock (long-term incentive plan)	$6,668	$8,322	$1,572
Notables and Miscellaneous	$1,215	$667	$333
Total Incentives**	$28,224	$30,570	$13,026

* *Amounts are net of PGE's pre-filing adjustments.*
** *Numbers may not sum due to rounding.*

Q. Why did PGE make these adjustments?

A. We made these adjustments to help mitigate the overall size of the rate increase. PGE has worked diligently to design incentive plans that provide reasonable incentive to attract and retain qualified individuals, to achieve corporate goals, and to benefit customers. This helps minimize turnover, increase efficiency, and produces positive financial results; all goals that directly and positively impact PGE's costs and value to customers. Although we have made these incentive reductions in this filing, we still believe that all of our incentive costs are prudent and appropriate.

Q. Are PGE's incentive adjustments consistent with adjustments made by PGE in prior general rate cases?

A. Yes. Our adjustments are consistent with the adjustments made by PGE in prior general rate cases, including UE 319.

A. Performance Incentive Compensation

Q. What is the Performance Incentive Compensation (PIC) Plan?

A. The PIC Plan is PGE's broad-based incentive program for most non-bargaining employees. The PIC plan rewards eligible employees with cash payments for performance tied to results that support PGE's corporate goals and lead to greater value for customers and stakeholders.

Q. Please explain how the PIC plan creates benefits for customers.

A. PGE's PIC plan creates customer benefit by basing the incentive pool on two goals that provide value to customers:

- Individual or Team Scorecard Goals: These scorecard goals are designed to stretch performance and promote individual growth and development, while achieving corporate operational goals (e.g., efficiency, meeting or improving operational standards). Strong individual performance is critical in achieving strong company performance, which in turn, leads to greater value for PGE's customers.
- Financial Performance: Financial strength can reduce customer rates through lower borrowing costs and, thus, a lower cost of capital.

Actual award amounts are based on employees' incentive targets and their performance relative to these goals.

B. Annual Cash Incentive

Q. What is the Annual Cash Incentive (ACI) Plan?

A. PGE's ACI Plan is an incentive plan for executives and key non-bargaining employees whose contributions have a strategic and measurable impact on the success of PGE's goals.

Q. Please describe the ACI plan's operational goals and how they align key employee performance measures with customer interests.

A. PGE aligned its ACI plan with customer interests by basing the incentive payouts on PGE's success in achieving four goals described below that deliver value to customers:

- Customer Satisfaction: This goal measures the overall satisfaction of PGE's retail customer groups using results from: 1) the average quarterly percent rating of the Market Strategies International (MSI) study for residential customers; 2) the average semi-annual percent rating of the MSI study for business customers; and 3) the annual results from the TQS Research, Inc. National Utility Benchmark of Service to Large Key Customers. The results of the three measures are weighted based on revenue from each retail customer group, respectively. High customer satisfaction rates are a key indicator that PGE is providing customers high quality service at a reasonable price.
- Electric Service Power Quality and Reliability: This goal uses annual results of the company's 1) System Average Interruption Duration Index (SAIDI), the average outage duration for each customer served; 2) System Average Interruption Frequency Index (SAIFI), the average number of interruptions that a

customer would experience; 3) Momentary Average Interruption Frequency Index (MAIFI), the average number of momentary interruptions that a customer would experience; and 4) Customer Average Interruption Duration Index (CAIDI), which was added in 2018. SAIFI, MAIFI, and CAIDI are weighted at 15% of this goal, while SAIDI is weighted at 55% of this goal. Our customers depend on PGE to deliver and maintain a high level of system reliability.

- Generation Availability: This goal measures the amount of time that our generating plants are available to produce energy. Plant availability positively influences power costs by ensuring that the lowest cost resources are available for dispatch.[14]
- Financial Performance: This goal measures actual earnings per share (EPS) relative to an EPS target established by our Board of Directors. PGE's financial strength will reduce customer prices through lower borrowing costs and, thus, a lower overall cost of capital. Financial strength also supports PGE's access to capital to support necessary investments that benefit customers.

C. Other Plans

Q. Please describe PGE's long-term stock incentive program.

A. PGE initiated its stock incentive plan in 2006 and it reflects current market practice; many publicly traded companies (including most utilities) provide long-term incentives to promote performance and retention of directors, officers, and key employees. These awards are earned and paid out in three-year cycles. The Public Utility Commission of Oregon (OPUC

[14] PGE Confidential Exhibit 702 provides plant availability statistics.

or Commission) approved this stock issuance in Docket No. UF 4226 and summarized the goals of the plan:

> "The Plan is part of the Company's overall compensation package and is intended to provide incentives to attract, retain, and motivate officers, directors, and key employees of the Company."[15]

PGE's 2019 forecast for its long-term stock incentive program is $8.1 million, but our request is approximately $1.6 million for the 2019 total long-term incentive expense. Our request reflects the removal of the Officer Long-term Incentive Program costs and a 50% reduction for other stock incentives as we have done in past rate cases.

Q. Does PGE have other programs that reward employees' exceptional performance?

A. Yes. Notable Achievement Awards (Notables) and other miscellaneous awards are given to employees on a case-by-case basis for exceptional performance. Notables are distributed to recognize employees' outstanding work on a specific project or task. PGE's 2019 forecast for Notables is approximately $0.7 million, but our request is approximately $0.3 million, reflecting a 50% reduction.

At times, and in specific situations, we have also employed other types of incentives, such as signing bonuses and retention payments, to obtain difficult-to-locate talent, in periods of critical skill competition, to motivate the completion of important tasks, or to hold employees in cases of future layoffs (e.g., Trojan decommissioning). However, these types of incentives are not included in the 2019 test year.

Q. Has PGE included any incentive costs for employees at the Boardman Plant?

A. No. As discussed in Docket No. UE 294, beginning in 2016, PGE removed all Boardman-related incentive costs from base rates. Beginning in 2016, employees working

[15] OPUC Order No. 06-356, p.1.

at the Boardman Plant are eligible only for the Boardman Retention/Reliability Plan, with costs recovered separately through Schedule 145.

VI. Benefits

Q. What is PGE's benefit compensation strategy?

A. PGE strives to maintain a benefits package that meets our employees' needs and balances the features and costs both among employee groups and against what other employers in our market provide to their employees. As with the other two compensation components (wages/salaries and incentives), PGE compares our benefits programs to the relevant market attributes. PGE also uses market information to create innovative program designs to provide greater employee choice and improve our ability to control costs. As a result, we believe that our total compensation package as filed is sufficient to attract and retain well-qualified and skilled employees and is reasonable for customers.

Q. Please describe the components of PGE's total benefits.

A. There are four major components: 1) health and wellness, 2) disability and life insurance, 3) post-retirement, and 4) miscellaneous benefits. These components are also typical parts of our competitors' offerings. As shown in Table 8 below, we project 2019 employee benefit costs of approximately $100.5 million. PGE's total benefit costs are expected to increase $18.2 million from 2017 to 2019. However, approximately $14.2 million of that increase is due to medical and dental costs increases exceeding inflation and higher FTE requirements from 2017 to 2018 (as supported in UE 319). At the same time, PGE's total benefit costs are expected to increase $4.0 million from 2018 to 2019 mostly due to inflation, which is partially offset by FTE decreases. The drivers of this increase, and PGE's efforts to benchmark its benefit costs, are discussed in more detail below.

Table 8
Total Benefits ($000)

Benefits Compensation Component	**2017 Actuals**	**2018 Budget**	**2019 Test Year**
Health and Wellness	$41,040	$50,948	$53,836
Disability and Life Insurance	$2,836	$4,051	$4,237
Post-Retirement	$37,197	$39,144	$40,008
Miscellaneous Benefits	$648	$1,355	$1,406
Benefits Administration	$597	$1,004	$1,031
Total Benefits*	$82,318	$96,502	$100,519

** Numbers may not sum due to rounding.*

Q. Does PGE use a benefits benchmark to measure and compare overall benefit costs?

A. Yes. PGE participates in the Willis Towers Watson Energy Services BENVAL Study, a biennial comparison of benefit values (all open health and dental, post retirement, disability, and life insurance plans) among peer utilities with similar revenues. BENVAL provides a complete competitive analysis of the value of a benefit program, including a comparison of a company's benefits plans against those of peer companies. Peer companies are those companies in similar industries with similar revenue sizes. The tools a company can use to affect medical costs are extremely diverse; BENVAL gathers all the relevant information related to a company's health care and other benefits plan offerings in order to accurately benchmark them against other peer groups. BENVAL is a leading benefits benchmark study used by utilities and other large industries to evaluate the cost of their benefits plans.

Q. Where does BENVAL place PGE in its medical and other benefit costs?

A. According to the 2017 BENVAL study, PGE's employer-paid non-bargaining medical costs along with PGE's entire benefit program were higher than the average of its peers. However, this higher than average result is partially offset by PGE's decision to include a 3.5% escalation rate in the budget for 2018 non-exempt wages and salaries, instead of the 4.5% rate forecast in 2018 by the Oregon Office of Economic Analysis. These survey results are provided as confidential PGE Exhibit 402C. Since the BENVAL study is a biennial survey, PGE will participate in this survey again in 2019. Based on past experience, we anticipate receiving survey results by the end of the second quarter in 2019.

Q. Please describe PGE's peer group in the BENVAL study.

A. In general terms, PGE's peer group includes 14 regulated utilities with annual revenue ranging from $1 billion to $3 billion. These peer utilities derive the majority of their revenue from the electric business. The peer group includes utilities across the U.S., with a balanced representation across the western and eastern regions.

Q. Please explain why Health and Wellness costs are forecasted to increase approximately $12.8 million from 2017 to 2019.

A. As supported in UE 319, the increase is primarily attributable to higher FTEs requirements, as well as increases in medical and dental rates from benefit providers. While PGE works hard to keep its medical and dental costs down, these costs are also driven by national trends and are not something that PGE can fully control. At a national and regional level, increases in medical and dental costs continue to outpace inflation. According to a June 2017 PricewaterhouseCoopers report,[16] the projected growth rate for medical costs is forecasted to be approximately 6.5% nationally. This compares to PGE's forecasted average annual increase of approximately 7.0% from 2017 actuals to the 2019 forecast.

PGE's benefits consultant, Mercer, provides PGE's forecasted rate increases for the 2019 forecast. Mercer uses national and regional trending data paired with PGE's employee demographics and usage trends in order to calculate a customized forecasted rate increase.

[16] See PGE's non-confidential work papers. Also available at http://www.pwc.com/us/en/health-industries/health-research-institute/behind-the-numbers.html.

Health care plan offerings and cost sharing for the main bargaining unit are a negotiated benefit and managed by a Taft-Hartley Trust.[17] We forecast that bargaining employee medical and dental plan premium costs will increase by approximately 7.0% in 2018 and 7.0% in 2019. Our forecast is based on a semi-annual survey of local insurance companies' annual claims cost trends performed by Mercer and actual employee experience in 2015 and 2016.

Q. What strategy is PGE employing to help slow the increase of its health care costs?

A. PGE's strategy is to align the features and costs of programs with the market and increase focus on employee wellness to control health care costs. We use various tools to execute our strategy. The largest tool PGE currently has at its disposal to help control future health care costs for both the company and employees is the transition from traditional medical plans to Health Savings Account-qualified (i.e., HSA-qualified) medical plans. In 2016, PGE began a three-year transition to HSA-qualified medical plans. [18]

For 2018 and beyond, PGE is offering only HSA-qualified plans to non-bargaining employees, and is offering the option to union employees. To help ease the transition, PGE has shifted some of the funds used for paying employee premiums in traditional plans to funding a beginning balance in employees' HSAs.

Q. Please briefly describe the differences between traditional medical plans and HSA-qualified medical plans.

A. Relative to traditional medical plans, HSA-qualified medical plans are designed with higher deductibles and higher maximum out-of-pocket limits. The HSA-qualified medical plan

[17] Health care plan offerings and cost sharing for union employees at Coyote, Port Westward and Carty are the same as those offered to non-bargaining employees.
[18] HSA-qualified plans are sometimes called high deductible plans.

design encourages wise use of health care services, because employees are responsible for 100% of service costs up to the medical plan's deductible, except for preventive care which is covered. The HSA-qualified medical plans also place a greater focus on overall wellness.

Q. Why does PGE include wellness programs as one of its total benefits components?

A. PGE offers wellness programs to provide early detection of risk factors, intervention and management of health issues. These programs promote healthier lifestyles, which contribute to lower medical premiums, increased morale, attendance, and productivity. Some of the services provided through these health programs include biometric testing, health risk appraisals, professional health coaching, obesity management, wellness reimbursements and disease prevention. Also included are occupational health services, which provide flu shots, health screening, and case management.

Q. Has PGE's transition to HSA-qualified medical plans led to an increase in PGE's employer paid per capita medical costs?

A. No. Confidential PGE Exhibit 403C provides our 2016 to 2019 projections of the Per Capita Employer Medical Contribution with and without the transition to the HSA-qualified medical plans. Without the shift to HSA plans that we started in 2016, medical costs per capita would have been higher than what we currently forecast.

Q. Previously you discussed the negotiation of the collective bargaining agreement for union employees at all sites other than Coyote, Port Westward and Carty. Were there any material changes to benefits in the terms of the CBA?

A. Yes. The Union agreed to include an HSA-qualified medical plan in the benefits offered to union employees. Benefit plans are an important component of the overall labor contract between the Union and PGE. While union employees will also have the choice of a traditional medical plan, rising health care costs were a concern during the negotiations and it was generally agreed that offering an HSA-qualified plan would be beneficial to bargaining employees and PGE.

Q. Please explain how PGE forecast its disability and life insurance benefit for 2019.

A. PGE's disability and life insurance benefits are comprised of union short-term disability (STD) insurance, long-term disability insurance, and retiree group life insurance for all employees.

PGE forecasts STD insurance costs of approximately $0.7 million in 2019. This represents a $0.1 million increase from 2017 and is the result of union wage increases for 2017 and 2018 coupled with incremental union FTEs.

PGE forecasts long-term disability medical costs for union and non-union employees to be approximately $2.3 million in 2019. PGE uses a forecast by Willis Towers Watson, a third party actuary, to estimate these expenses. Actual long-term disability costs fluctuate from year-to-year, sometimes significantly. The actuarial forecasts are driven by factors such as the discount rate, health care trend assumptions, number of participants, and demographics of the participant population. The expense in a given year is calculated as the difference between beginning and ending liabilities, plus the benefits actually paid by PGE in that year.

PGE forecasts retiree group life insurance costs to be approximately $1.3 million in 2019. For union and non-union retirees, PGE pays for a basic level of coverage for life insurance. Active union and non-union members otherwise pay for their own life insurance.

Q. What is included in PGE's Post-Retirement benefits costs?

A. PGE classifies its 401(k) plan and the PGE Pension Plan as post-retirement benefits. For purposes of this testimony, we also present the Health Reimbursement Account (HRA) as a post-retirement benefit.[19]

Q. Why are post-retirement benefits important?

A. Post-retirement benefits support employee recruitment and are an effective way to retain talent. Providing strong post-retirement benefits is a great way to enhance the total compensation package to attract well-qualified, skilled employees in the current competitive marketplace.

Q. What is PGE's 401(k) forecast for 2019?

A. PGE's 401(k) costs are based on employee contributions and PGE's match, up to plan maximums, and include an employer contribution for union employees and non-union employees hired after February 1, 2009. These costs change with base wage and salary levels and employee participation. From 2017 to 2019, costs associated with the 401(k) are expected to increase from $20.7 million to $23.3 million.

Q. What is PGE's HRA forecast for 2019?

A. PGE's HRA provides a post-retirement benefit to cover a portion of health care expenses and premiums for employees who retire from PGE. For non-bargaining employees, only those who retire from PGE will receive any HRA benefit. For these employees, PGE places funds into a notional account for retiree HRA benefits. Additional union HRA costs relate to the accumulation of notional hours for current employees and retirees receiving current HRA benefits. Total HRA costs for 2019 are expected to be approximately $2.3 million.

[19] To comply with ERISA accounting guidelines, PGE classifies the HRA as a health and wellness benefit, even though employees do not receive the benefit until after retiring from PGE.

Q. What is PGE's pension cost forecast for 2019?

A. PGE's 2019 pension cost is forecasted to be $21.5 million (or approximately $14.5 million after capitalization). PGE's 2019 total pension expense is slightly lower compared to 2017. PGE's pension cost forecast does not include the changes required by the Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) titled, *Compensation – Retirement Benefits [Topic 715]: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost)*. In March 2017, FASB issued the ASU update No. 2017-07 and proposed the ASU would take effect January 1, 2018.

The amendments in the ASU will allow only the service cost component of pension costs to be eligible for capitalization. However, per the stipulation in UE 319, PGE is capitalizing pension and post-retirement plans in a manner consistent with PGE's method prior to the issuance of FASB ASU 2017-07.

Q. How is pension expense calculated?

A. Pension expense, more commonly known as "FAS 87 net periodic benefit cost,"[20] represents the cost of maintaining an employer's plan, and is reported on the company's income statement. Pension expense consists of the following components: service cost, interest cost, expected return on assets, amortization of prior service cost, and amortization of net gains or losses. As part of its pension expense determination, PGE must identify an expected long-term rate of return and a discount rate.

[20] PGE records its pension expense based on Accounting Standards Codification (ASC) 715, "Compensation – Retirement Benefits," which prior to July 1, 2009, was known as Statement of Financial Accounting Standards No. 87 or "FAS 87."

Q. What assumption does PGE use for its expected long-term rate of return?

A. Based on the pension plan's asset allocation, the pension investment portfolio is expected to yield a long-term rate of return of 7.0%. This estimate is developed based on a distribution of long-term expected return information provided by Mercer Investment Management Company.

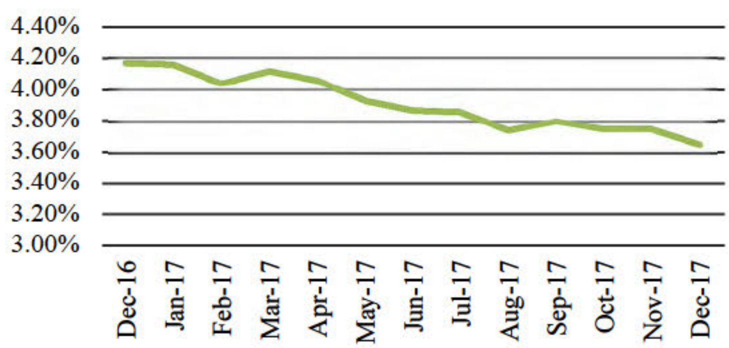
Q. What assumption does PGE use for its discount rate?

A. PGE uses a discount rate of 3.64%, which is an average of the interest rates of a group of long-term high quality AA-rated bonds. The discount rate is provided by Willis Towers Watson, and the methodology is determined in accordance with Generally Accepted Accounting Principles.

Q. Will the discount rate change if the current interest rate environment changes?

A. Yes. Interest rates are subject to uncertainty as the economic and political environment continues to develop. Figure 1 shows the change in discount rates since December 2016. Discount rates have declined year-over-year, and continue to be at historic lows.

Figure 1
Discount Rates (December 2016 – December 2017)



Q. Does PGE have a proposal for managing the uncertainty in the discount rate assumption during this rate case?

A. Yes. PGE will continue to monitor discount rates during the course of this proceeding, and we propose submitting a final discount rate assumption for the 2019 test year pension cost no later than September, 2018 using the same methodology. This proposal allows PGE, and parties, to monitor the interest rate environment throughout the rate case and establish a discount rate assumption that benefits from a greater understanding of more current market conditions.

Q. Please discuss the current state of PGE's pension plan.

A. Overall, the funded status of PGE's pension plan continues to be slightly above 70%. With discount rates remaining at a historically low level and continuing to fall, the nominal growth of PGE's pension liabilities is currently outpacing the growth of pension plan assets, even with the exceptional growth in 2017. In other words, while PGE has experienced above average plan returns,[21] they are still not enough to cover the growth of future expected liabilities. Further compounding this issue is the increase in Pension Benefit Guaranty Corporation (PBGC) premiums,[22] which has put additional upward pressure on pension expense.

Q. How is PGE addressing these issues?

A. PGE looks at strategies to improve the funded status of the plan and reduce the risk associated with both PBGC premium increases and discount rate fluctuations. We expect to make significant required cash contributions into the plan over the coming years and we

[21] PGE's pension plan total fund performance ranked in the top decile among similar sized pension plans for the last three years ending September 30, 2017.
[22] The PBGC per participant fee has increased 138% in the last 10 years while the variable rate has increased 332% in the same time period. Rates will continue to rise year after year since the rates are indexed for wage inflation.

continue to follow an investment strategy that actively maximizes the risk-adjusted returns of plan assets. We do not currently expect that our required cash contributions will significantly increase the funded status of our pension plan or significantly reduce FAS 87 expense over the short-term. However, PGE actively reviews liability management strategies for available options to prudently increase our funded status, reduce plan risk, and reduce our overall plan expense and we plan to keep OPUC Staff informed of any potential liability management strategies, should sensible opportunities arise.

Q. Please explain PGE's forecast cost for miscellaneous employee benefits.

A. Miscellaneous benefits are additional, low-cost tools that PGE uses to attract, retain, and develop well-qualified, skilled employees. We expect to spend approximately $1.4 million in 2019. Although small in dollars, these tools help balance employer provided benefits with the changing realities of our demographics and position in the marketplace for employees. Examples of PGE's miscellaneous benefits include educational assistance, service awards, and a public mass transit benefit.

- Education Assistance: $0.5 million – This program reimburses employees for education that enhances learning and development. It can be applied to classes that lead to a certification or undergraduate/graduate degree as well as classes that enhance technical knowledge. This program increases PGE's number of qualified employees available to fill open positions. Sponsoring career development is also a prime recruiting tool and source of employee motivation and satisfaction, which also aids retention. This program is also useful to PGE's efforts to strengthen the technical skillset and versatility of its employees.

- Service Awards: $0.2 million – As a retention and morale strategy, PGE honors employees for their years of service at five-year anniversary intervals, consistent with industry practice.
- Public Mass Transit Benefit: $0.6 million – PGE and the City of Portland, among other companies and institutions, continue to encourage alternatives to personal vehicle transit and as a tool for recruitment and retention strategy. PGE began offering a public mass transit benefit on January 1, 2018. This benefit is designed to ease transit barriers for individuals, particularly those who see the cost (or limited availability) of parking as an obstacle to working in downtown Portland and other PGE locations serviced by Tri-Met. Incenting travel via public mass transit into Portland also improves our ability to build a diverse workforce, because it makes downtown Portland a more accessible destination.

Q. What is PGE's 2019 cost for benefits administration?

A. PGE forecasts 2019 benefits administration costs to be approximately $1.0 million, which is consistent with costs included in UE 319.

VII. Summary and Qualifications

Q. Please summarize your testimony.

A. PGE must provide a total compensation package sufficient to attract and retain the well-qualified and skilled employees PGE needs to operate its business effectively and efficiently, and to encourage performance beneficial to PGE and our customers. To do this, PGE designs its total compensation program with reference to the labor markets in which we compete. This approach provides a total compensation structure, comprised of wages and salaries, incentives, and benefits, that as proposed will be competitive and cost effective.

Q. Ms. Mersereau, please summarize your qualifications.

A. I received a Bachelor of Arts degree in Business Administration: Human Resources and Management with a minor in Economics from Washington State University. I also hold a Senior Professional in Human Resources (SPHR) designation. My professional Human Resources career spans nearly thirty years and includes various roles at PGE for the last nine years, as well as positions with Hilton Hotels Corporation, Marsh USA Inc., and Waldron Consulting. I joined PGE's Human Resource (HR) organization in 2009. I've served employees in Line Operations as well as T&D engineers, Substation Operations, Service & Design, and Public Policy employees. In 2014, I became the Employee Services Manager, where I led HR Operations including HR Systems Reporting & Analytics, Payroll, Service Center, Health Services, and other areas. I became Vice President of HR, Diversity & Inclusion in 2016. In this position, I am responsible for safety, talent acquisition and management, employee engagement, change management, total rewards, health and wellness, diversity and inclusion, and corporate project management.

I'm an active member of the community with a passion for education and workforce development. In 2017, I was appointed by Oregon Gov. Kate Brown to the Oregon Workforce Investment Board. I also serve as Vice Chair for Impact NW and the board of Dress for Success Oregon, and I'm a member of the Partners in Diversity Leadership Council.

Q. Ms. Neitzke, please summarize your qualifications.

A. I received a Bachelor of Science degree in Business Administration with an emphasis in Finance and a Post Baccalaureate degree in Accounting from Portland State University. I am a Certified Public Accountant. Prior to joining PGE in 2007, I worked at KPMG where I served in various publicly held companies as an external auditor over the course of ten years. I joined PGE in 2007 and have held various finance related management roles including financial reporting, treasury, corporate planning and supply chain. I became the Director of Compensation and Benefits in early 2017.

Q. Does this conclude your testimony?

A. Yes.

VIII. List of Exhibits

PGE Exhibit	Description
401	PGE FTEs - 2015 Actuals through 2019 Test Year Forecast
402C	2017 BENVAL Ranking – Entire Benefit Program
403C	2015-2019 Per Capita Employer Medical Contribution

PGE FTEs - 2015 Actuals through 2019 Test Year Forecast

DIVISION	2015 FTE (PGE Share)	2016 FTE (PGE Share)	2017 FTE (PGE Share)	2018 BUD FTE (PGE Share)	2019 GRC FTE (PGE Share)	FTE Delta 2017 -2019	Annual % Delta 2017 -2019
A&G - INFORMATION TECHNOLOGY Total	234.8	272.4	304.3	341.7	321.2	16.8	2.7%
ADMINISTRATIVE AND GENERAL Total	370.5	367.3	372.1	413.6	413.9	41.7	5.5%
CUSTOMER ACCOUNTS Total	379.6	382.7	400.0	410.4	384.5	(15.4)	-1.9%
CUSTOMER SERVICE Total	87.8	85.7	85.4	95.8	95.7	10.3	5.9%
GENERATING - BEAVER Total	50.2	48.9	47.1	48.5	48.5	1.5	1.6%
GENERATING - BIGLOW Total	7.4	8.1	8.6	9.0	9.0	0.4	2.5%
GENERATING - BOARDMAN Total	98.9	88.3	84.2	87.9	87.9	3.6	2.1%
GENERATING - CARTY Total	8.6	21.0	21.3	22.7	22.9	1.6	3.8%
GENERATING - COYOTE Total	17.1	17.0	17.6	17.9	17.9	0.3	0.9%
GENERATING - OTHER Total	302.3	309.7	326.1	348.8	348.2	22.2	3.3%
GENERATING - PORT WESTWARD Total	25.3	25.8	26.9	29.6	29.6	2.7	5.0%
GENERATING - TROJAN Total	12.1	11.9	12.6	16.9	16.9	4.3	15.7%
GENERATING - TUCANNON Total	4.4	5.0	4.5	5.0	5.0	0.5	5.5%
TRANSMISSION & DISTRIBUTION Total	922.5	957.7	1,044.9	1,184.6	1,184.6	139.6	6.5%
Grand Total	2,521.4	2,601.4	2,755.5	3,032.2	2,985.8	230.3	4.1%

Adjusted Totals by Division

IT	234.8	272.4	304.3	341.7	321.2	16.8	2.7%
Unfilled Position Adjustment				(8.9)	(14.4)	(14.4)	
Adjusted IT Totals	234.8	272.4	304.3	332.8	306.7	2.4	0.4%
A&G	370.5	367.3	372.1	413.6	413.9	41.7	5.5%
Unfilled Position Adjustment				(10.7)	(24.5)	(24.5)	
Adjusted A&G Totals	370.5	367.3	372.1	402.9	389.4	17.2	2.3%
Adjusted A&G/IT Totals	605.3	639.7	676.5	735.7	696.1	19.6	1.4%
Customer Accounts	379.6	382.7	400.0	410.4	384.5	(15.4)	-1.9%

DIVISION	2015 FTE (PGE Share)	2016 FTE (PGE Share)	2017 FTE (PGE Share)	2018 BUD FTE (PGE Share)	2019 GRC FTE (PGE Share)	FTE Delta 2017 -2019	Annual % Delta 2017 -2019
Unfilled Position Adjustment				(33.7)	(4.6)	(4.6)	
Adjusted Customer Accounts Totals	379.6	382.7	400.0	376.7	380.0	(20.0)	-2.5%
Customer Service	87.8	85.7	85.4	95.8	95.7	10.3	5.9%
Incremental FTEs offset by Other Revenue	(19.7)	(20.1)	(20.9)	(20.6)	(20.6)	0.3	-0.8%
Adjusted Customer Service Totals	68.0	65.6	64.5	75.2	75.1	10.6	7.9%
Adjusted Customer Accounting/Service Total	447.6	448.2	464.5	451.9	455.1	(9.4)	-1.0%
Generation	526.3	535.7	548.7	586.1	585.9	37.2	3.3%
Unfilled Position Adjustment				(27.4)	(23.7)	(23.7)	
Adjusted Generation Total	526.3	535.7	548.7	558.8	562.2	13.5	1.2%
T&D	922.5	957.7	1,044.9	1,184.6	1,184.6	139.6	6.5%
Unfilled Position Adjustment				(31.5)	(30.5)	(30.5)	
Adjusted T&D Totals	922.5	957.7	1,044.9	1,153.0	1,154.1	109.2	5.1%
Unadjusted Total	2,521.4	2,601.4	2,755.5	3,032.2	2,985.8	230.3	4.1%
Unfilled Position Adjustment	-	-	-	(112.2)	(97.7)	(97.7)	
Incremental FTEs not in prices	(19.7)	(20.1)	(20.9)	(20.6)	(20.6)	0.3	
Adjusted Grand Total	2,501.7	2,581.3	2,734.6	2,899.4	2,867.5	132.9	2.4%
Match	-	-	-	-	-	0.0	

Exhibit 402C

Protected Information Subject to Protective Order 18-047

Exhibit 403C

Protected Information Subject to Protective Order 18-047

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jim Lobdell
Greg Batzler

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Greg Batzler. I am a Senior Regulatory Analyst in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $180.8 million in administrative and general (A&G) costs in 2019 and compare it to 2017 actuals of $176.1 million.

Q. What functions are classified as A&G and what are the costs of those functions?

A. We classify A&G as those back-office functions that support PGE's direct operations to deliver electric power to customers, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT). We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[1] PGE Exhibit 501 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2017 (actuals) through 2019 (test year forecast). Table 1 below, summarizes the major A&G costs by functional area.

[1] FERC defines Administrative and General expenses as those that fall within FERC accounts 920 through 935.

Table 1
A&G Costs by Major Functional Area ($ millions)

Major Functional Areas	**2017 Actuals**	**2018 Budget**	**2019 Forecast**	**Delta (2017 to 2018)***	**Delta (2018 to 2019)***	**Delta (2017 to 2019)***
Facilities	$ 5.9	$ 6.7	$ 6.3	$ 0.8	$ (0.4)	$ 0.4
Accounting/Finance/Tax	10.1	11.2	11.5	1.1	0.4	1.5
HR/Employee Support	11.3	13.0	13.6	1.7	0.6	2.3
Insurance, Injuries and Damages, etc.	12.3	12.2	12.2	(0.2)	0.0	(0.1)
Legal	6.1	5.3	5.5	(0.8)	0.3	(0.5)
Regulatory Affairs/Compliance	2.9	3.5	3.6	0.6	0.1	0.7
Corporate Governance	5.1	5.5	5.6	0.3	0.2	0.5
Business Support Services	2.8	2.6	2.6	(0.2)	0.1	(0.1)
Environmental Programs	2.3	2.2	2.3	(0.1)	0.1	0.0
Corporate R&D	1.8	2.2	3.2	0.4	1.0	1.4
Contract Services/Purchasing	2.1	2.2	2.3	0.1	0.1	0.2
Security and Business Continuity	2.4	2.9	3.0	0.5	0.1	0.6
Corp Communications/Public Affairs	2.5	2.3	2.4	(0.2)	0.1	(0.1)
Hydro Licensing	0.1	0.1	0.1	0.0	0.0	0.0
Performance Management	1.2	1.8	1.9	0.6	0.1	0.7
Governmental Affairs	1.2	1.2	1.3	0.0	0.0	0.1
Total for Major Functional Areas*	**$ 70.0**	**$ 74.7**	**$ 77.5**	**$ 4.8**	**$ 2.8**	**$ 7.5**
IT: Direct and Allocated	$ 12.0	$ 12.4	$ 15.5	$ 0.4	$ 3.1	$ 3.4
Labor Cost Adjustment	-	(2.1)	(2.1)	(2.1)	0.0	(2.1)
Membership Costs	3.2	3.5	3.6	0.3	0.1	0.4
Incentive Plans (net of capital allocations)	28.2	30.6	13.0	2.3	(17.5)	(15.2)
Severance	1.5	1.3	1.3	(0.2)	0.0	(0.2)
Regulatory Fees	7.8	7.7	7.9	(0.1)	0.2	(0.1)
General Plant Maintenance	2.4	2.8	2.9	0.4	0.1	0.5
Net PTO	6.3	6.3	6.6	0.0	0.3	0.3
Net Loadings	0.0	0.0	0.0	0.0	0.0	0.0
Employee Benefits (net of capital allocations)	49.2	58.7	62.6	9.5	4.0	13.4
Corporate Allocations	(6.4)	(8.1)	(9.7)	(1.7)	(1.7)	(3.4)
Revolver Fees, Margin Net Int., Broker Fees	1.8	2.1	1.8	2.1	(0.2)	0.0
Total Other A&G Costs*	**$ 106.1**	**$ 115.1**	**$ 103.3**	**$ 9.0**	**$ (11.8)**	**$ (2.8)**
Total A&G*	**$ 176.1**	**$ 189.9**	**$ 180.8**	**$ 13.8**	**$ (9.0)**	**$ 4.7**

** May not sum due to rounding.*

Q. Please explain the forecasted increase in A&G costs from 2017 to 2019.

A. As discussed in PGE's 2018 General Rate Case filed in Docket No. UE 319 (UE 319), the forecasted increase occurs between 2017 and 2018 (approximately $13.8 million). A copy of PGE Exhibit 600 from UE 319 is provided here as PGE Exhibit 502.

Q. Do A&G costs increase from 2018 to 2019?

A. No. From 2018 to 2019, A&G costs decrease by approximately $9.0 million.

Q. What are the primary drivers for the increase in A&G costs when comparing 2017 actuals to the 2019 test year?

A. The increase in A&G costs is attributable to two primary drivers: 1) Employee Benefits, as discussed in PGE Exhibit 400, largely driven by increasing health care costs; and 2) Human Resources, driven by increasing demands on PGE's Talent Acquisition and Training departments. While we actively manage costs associated with these drivers, they are, to some extent, external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control.

Q. Will you discuss any additional A&G related items?

A. Yes. In addition to the drivers highlighted above, we will discuss the following:

- Research and Development (R&D), driven by PGE's continued engagement in R&D on behalf of customers to preserve and improve system efficiency, reliability, and anticipate technological changes that could alter the grid and our operations;
- Increasing security costs, driven by the growing recognition of the potential for detrimental events plus PGE's, and our regulating bodies', increasing emphasis on protecting critical energy infrastructure;

- Cost savings for customers resulting from consolidating and centralizing various individual CEB/Gartner[2] memberships to one corporate membership; and
- Insurance costs, as prudent insurance coverage is integral to PGE's operations.

Q. Are there any offsetting cost savings or efficiencies reflected in the 2019 test year for A&G operations?

A. Yes. First, we exercised our renewal rights under our lease agreement for the World Trade Center (WTC) location, resulting in a $2.5 million savings per year. This saving is being applied to PGE through the WTC cost allocation to lessen the rate impact on customers. In addition, we consolidated the management for Investor Relations and Corporate Finance, resulting in an approximate $0.1 million cost savings in 2019. Finally, we centralized the procurement of our CEB/Gartner membership subscription, resulting in a 10% discount per year (approximately $42,000). Additional details on membership costs can be found in Section III below.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: Primary A&G Cost Increases;
- Section III: Other Items;
- Section IV: Summary; and
- Section V: Qualifications.

[2] Gartner, Inc., the world's leading information technology research and advisory company acquired CEB, Inc., formerly Corporate Executive Board, in April 2017 and is currently branded as "CEB, now Gartner", aka, CEB/Gartner.

II. Primary A&G Cost Increases

A. Employee Benefits

Q. Please describe PGE's employee benefits package.

A. PGE strives to maintain an employee benefits package that meets our employees' needs and balances the features and costs among employee groups against what other employers in our market provide. There are four major components to our benefits package: 1) health and wellness; 2) disability and life insurance; 3) post-retirement; and 4) miscellaneous benefits.

Q. How much do you expect benefit costs to increase from 2017 to 2019?

A. The estimated increase in benefit costs from 2017 to 2019 is approximately $13.4 million. These costs include such items as health and dental plans, 401(k) plans, pension costs, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary driver of the increase in benefit costs continues to be health care, which reflects escalation and other cost pressures. PGE Exhibit 400 explains in greater detail how the compensation and benefits-related costs are affected by these increases and how PGE must address them to remain competitive in the market for specialized and qualified labor.

Q. Are offsetting decreases reflected in the 2019 test year to help mitigate the increase in benefits costs?

A. Yes. This increase is partially offset by a decrease in PGE's incentive request, representing a reduction of approximately $15.2 million from 2017 actuals. Please note that the employee benefit amounts in Table 1 above represent the "net" changes within A&G. PGE

Exhibit 400 explains the gross corporate forecast for these costs.[3]

B. Human Resources

Q. Please summarize the reasons for the cost increase in your Human Resources department.

A. The forecasted cost increase in PGE's Human Resources is attributable primarily to Talent Acquisition and Technical Training. PGE's costs for these support services are forecasted to increase from approximately $4.5 million in 2017 to $5.4 million in 2019. Approximately $0.7 million of the increase occurs between 2017 and 2018 and is consistent with the forecast presented in UE 319.

Q. What adjustments has PGE made to these areas to reflect the outcome of UE 319?

A. For 2018 and 2019, PGE included a budget reduction in Human Resources of $0.4 million to account for the results of UE 319. This budget reduction is reflected under department (RC) 809 in PGE's work papers for PGE Exhibit 501.

Q. Please describe the drivers behind PGE's increase in Talent Acquisition costs.

A. As discussed in UE 319 and PGE Exhibit 400, PGE continues to see an increase in labor requirements, coupled with a tightening of the labor market, which is placing increased demands on Talent Acquisition staff, who continue to work beyond normal hours. PGE's Talent Acquisition department has seen its actual costs increase by an annual average of over 8.0% from 2015 through 2017, and we expect this trend to continue as PGE's business needs continue to grow. As shown in Table 2, below, the number of annual job requisitions that PGE's Talent Acquisition department has filled began increasing substantially in 2015

[3] Net benefit amounts in A&G represent the amounts remaining in A&G after labor loadings apply certain portions of these costs to capital projects and "below-the-line" activities. The gross corporate forecast for benefits refers to the total compensation costs embedded in the 2019 test year.

and are expected to remain at a high level. This elevated level of hiring reduces Talent Acquisition's effectiveness, and cannot be maintained at the current staffing levels. Additionally, with a high number of senior professionals and field personnel (e.g., linemen, meter-service technicians) nearing retirement at PGE and throughout the utility industry, the demand for skilled utility professionals has increased.

Table 2
Filled Position Requisitions

Year	Filled Requisitions
2014	638
2015	838
2016	930
2017	1,043

Q. Are there other pressures that increase the workload for Talent Acquisition?

A. Yes. There is one other key pressure that is external to PGE: the tight labor market within Oregon and across the nation. Oregon's unemployment rate has steadily declined in the past few years, with the unemployment rate for the Portland metropolitan area decreasing from 5.1% in October 2015 to 4.2% in October 2017. As discussed in PGE Exhibit 400, this has increased the difficulty and time requirements to recruit, hire, and retain certain professional classifications. One effect of this increasingly tight labor market is the steady increase year-over-year of the time to fill (TTF) open positions.

Q. What is the impact of increased hiring activities at PGE on O&M costs for the 2019 test year?

A. Increased hiring forces Talent Acquisition to increase its budget for outside services, which we use to attract and recruit qualified applicants for senior level professional and field personnel positions. To address this issue, Talent Acquisition plans to increase the quantity of job advertisements placed on recruitment sites while also expanding the scope of job advertisement sites used to attract and recruit talent. Talent Acquisition will also continue to support management in its selection process and engage in proactive recruiting strategies such as career fairs, data-driven analytics, college internships, line pre-apprenticeship programs, and social media outreach.

Q. What additional measures is Talent Acquisition taking to address increased hiring pressures and maintain recruiting competitiveness?

A. As discussed in UE 319, Talent Acquisition is adding two FTEs in 2018 to meet increased hiring demands and maintain recruiting competitiveness. Additionally, Talent Acquisition is using strategic workforce planning to better integrate its long-term planning for recruitment and hiring with key elements in PGE's overall strategic direction. Through this integration, coupled with the leveraging of data analytics and existing resources, PGE will be better able to understand, prepare for, and meet our long-term hiring needs by assessing generational workforce changes (e.g., baby boomers retiring) and by preparing for anticipated workforce gaps through proactive recruitment strategies.

Q. What is driving the increase related to Technical Training?

A. Technical Training is seeing an overall increase to both the amount and scope of required training due to the following:

- PGE is developing continuing education classes to maintain skill agility within our workforce and to address changes within the electric industry;
- As PGE implements and integrates new systems and programs, we must retrain PGE employees and contractors on their job-specific requirements, per Occupational Safety and Health Administration (OSHA) standard 1910.269;[4] and

[4] See https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=standards&p_id=9868 for additional information.

- As we continue to hire new employees throughout 2018 and 2019, PGE will need increased support for technical training classes, per OSHA standard 1910.332.[5]

Q. Please describe the expansion in PGE's training demands.

A. In order to meet regulatory training requirements while maintaining skill agility within our workforce, PGE is experiencing the following increases to training demands:

- Additional pre-apprenticeship program offerings and continued growth associated with the existing apprenticeship program;
- New curriculum development including safety leadership, service design management, and soft tissue injury prevention;
- Increasing mandatory regulatory training and development;
- Additional support for new employee training;
- New engineer curriculum for transmission, distribution and generation engineers; and
- The creation of skill tracks for specialized positions to identify key skills and competency gaps for specific roles.

Q. Does the 2019 test year forecast for Technical Training differ significantly from the 2018 test year forecast presented in UE 319?

A. No. PGE's costs for 2019 only reflect escalation of our 2018 budget, which is consistent with amounts forecast and included in UE 319. Additionally, as discussed above, we reduced our Human Resources budget by approximately $0.4 million for 2018 and 2019 to reflect the outcome of UE 319.

[5] See https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=standards&p_id=9909 for additional information.

III. Other Items

A. Research and Development

Q. Why does PGE engage in corporate R&D activities?

A. PGE conducts R&D on behalf of customers to both preserve and improve system efficiency, reliability, and safety, while anticipating changes that could profoundly alter the grid, the ways we manage it, and the services we offer customers. This includes addressing technological challenges inherent in the demand for renewable, clean, and reliable energy. PGE must continue to be involved in, and provide support for, programs of increasing importance such as demand response, distributed energy resource (DER) management and system resiliency while doing so in a cost-effective manner.

Q. What are your forecasted 2019 costs for PGE's corporate R&D activities?

A. For 2019, we forecast approximately $3.2 million in R&D expenses.[6] This reflects an increase of approximately $1.0 million over 2018 projected expenditures. PGE's proposed increased spending supports projects that will address the significant changes and new technologies facing PGE and the electric industry.

Q. Please describe PGE's R&D strategy as it results in a planned expenditure of $3.2 million.

A. PGE's 2019 R&D projects will further our understanding of and primarily relate to, Smart Grid (SG), applications (including new customer services), System Reliability (SR), Renewable Power (RP), Operational Efficiency (OE), Energy Storage (ES), System Resiliency (SY), and Safety (S). PGE will advance the operation of our increasingly smart

[6] Approximately $3.0 million is budgeted for 2019 R&D projects and the remainder is for administrative expenses. 2017 R&D project actuals of $1.8 million were charged to Account 930 Administrative & General Expenses. 2017 R&D administrative expenses of $0.2 million were charged to Customer Services Account 908.

and integrated grid by leveraging technologies that deliver customer value and system benefits in a constantly changing landscape. PGE must plan ahead, successfully pilot, and integrate proven technologies that drive customer value. These 2019 R&D proposed projects will directly enhance the planning, piloting and integration of information, resulting in greater reliability, resiliency, safety, security, power quality, and efficiency of PGE's transmission and distribution network.

R&D projects are vetted by an internal R&D Steering Committee. The Committee's charge is to approve projects that best contribute to PGE's ability to evaluate and deploy technologies and resources that will benefit customers help shape Oregon's energy future, and conform to customer priorities for an even more reliable, smart, and sustainable electric power system.

Table 3 below, provides a list of those 2019 R&D project categories, and the number of prospective projects within each category. We also provide a more complete list of expected projects with descriptions and project benefits in PGE Exhibit 503.

Table 3
Summary of 2019 R&D Projects by Category

Category	Approx. Cost (in thousands)	Number of Projects
Smart Grid	1,230	13
System Reliability	368	5
Renewable Power	215	7
Operational Efficiency	671	6
Energy Storage	157	3
System Resiliency	90	2
Safety	339	3
Total	3,070	39

Q. Please provide an example of current R&D expenditures that will result in future benefits to customers.

A. Many of PGE's R&D projects pursue the integration of existing technology in new applications that, if successful, will provide significant benefits to customers. An example of this is the development and implementation of the Consumer Technology Association (CTA) Standard 2045 (CTA-2045) specification, which standardizes the interface for customers to add communications to consumer appliances for energy management. PGE has focused primarily on the Standard's application to water heaters. When broadly adopted, it will enable broad-scale, cost-effective thermal storage for individual residences. Projects like this develop over many years, but only continue if critical milestones are met. PGE has invested approximately $0.5 million over eight years in the Electric Power Research Institute (EPRI) programs to help develop and commercialize the CTA-2045 Standard. The Standard was published in January of 2013, and PGE expects the first water heaters with this standard interface built into the tank to reach the market in 2019. The effect is to reduce the installed cost per-kW of demand response by more than 50%, and more than triple the achievable potential demand response (over 15 years). Instead of capturing only 30 MW of demand response in multi-family dwellings at $800/kW, PGE will have the potential to capture close to 100 MW of demand response at less than $400/kW. This would represent savings of $40 million relative to the cost of a 100 MW peaking plant, more than twice PGE's entire R&D portfolio expenditures over the last 20 years.

Q. Does PGE take into account cost effectiveness in funding R&D projects?

A. Yes. PGE increases cost effectiveness for customers by leveraging the R&D funds through partnering with other entities. That way, our customers get the benefit of their dollars at work as well as the dollars of other funding groups. PGE has been investing an increasingly large portion of the R&D budget in jointly funded research with EPRI and, in some cases, the Bonneville Power Administration (BPA). In 2017, PGE invested approximately $0.5 million in EPRI related programs and products, gaining access to approximately $18.3 million in research. Specific examples where value has been or will be derived are discussed below:

- Distribution planners face a new reality, shaped in part by the addition of distributed energy resources. Utilities are determining the optimal locations for DERs, as well as the planning for their integration into distribution systems. PGE also needs to have a clearer understanding of our distribution system's ability to host DERs. Just as capacity planning studies are performed for accommodating new load, hosting capacity planning studies are needed to accommodate new DERs. PGE's goal is to complete a system-wide Hosting Capacity assessment by late 2018 using internal resources. The hosting capacity analysis directly ties to EPRI Programs P174 (SG), P180 (OE), and P200 (SG).

  By participating in EPRI research activities, PGE may access tools and leverage the studies of other utilities, substantiating and strengthening our estimates. EPRI's new Drive Tool costs $20,000 and will require a modest investment of internal resources. PGE previously hired a consulting firm to perform a Hosting Capacity assessment on a sample set of seven feeders, which cost $16,000. Had PGE elected to continue using external consultants, a system-wide assessment (600+ feeders) would have cost approximately $1.4 million.

- PGE is also planning a supplemental project on Integrated Energy Storage Modeling and Analysis. Rather than fund this project on its own, PGE will be able to leverage EPRI and other participant engineering resources to apply advanced grid modeling tools and assess optimum placement for new storage devices.

- PGE has used EPRI's Cybersecurity Metrics work to develop an operational metric plan for our Information Security Program. In this case, the metrics would measure the maturity and success of the security program, similar to SAIDI[7] which measures power delivery reliability. There are many cybersecurity models available in the IT space, but EPRI customized their security metrics to the utility space, providing more value than generic models.

Q. Does PGE work with other research partners?

A. Yes. In addition to shared research with EPRI and the BPA, PGE continues to work with industry partners and universities on shared projects that support regional renewable power research related to wind, wave, and solar technology, battery backup field demonstrations, non-wire solutions to transmission congestion, and transportation electrification.

Q. Please explain how customers benefit from these partnerships.

A. As stated previously, the value is the leverage of PGE funds with others'. In doing so, PGE and its customers receive 100% of the benefits for a fraction of the overall research costs; this often means receiving useful information much earlier than if we did not contribute or otherwise engage with research partners. University partners treat PGE's R&D dollar contributions as part of required matching funds for much larger federal or other institutional grants, thus leveraging PGE's expenditures in research expected to deliver long-term customer benefits. For 2019, PGE plans to co-sponsor specific projects with Portland State University, Oregon State University, Washington State University, the

[7] SAIDI - System Average Interruption Duration Index.

University of Oregon, and the Oregon Institute of Technology. PGE Exhibit 503 describes PGE's 2019 proposed co-sponsorship research projects.

Q. Are there instances where R&D research projects may be shifted from one year to another?

A. Yes. Many PGE research projects are multi-year projects. Others can be delayed and/or reconfigured based on changing conditions. Consider, for example, PGE's Transmission and Distribution (T&D) Analytics project in 2017. Vendor issues resulted in delays, and ultimately the project was redefined and will be funded in 2018 (see PGE Exhibit 504, "Data Analytic & Visualization POC" project.) Given the vendor-caused delays for 2017, the R&D Steering Committee instead funded the Biglow Canyon Wake Effects Research and Seismic Analysis and Post Event Transmission Impacts research project. PGE expects this research to potentially enable improved output from existing renewable facilities at a relatively low cost. If output were improved, it would increase the amount of renewables on PGE's system and lower customer costs.

Q. What are the risks of not participating in these and other prospective R&D projects?

A. The risks are the loss of the early learning that comes from participation. The implementation of projects by PGE can create internal subject matter experts (SMEs) and a body of knowledge related to the potential impact of new technologies on PGE's system. For example, in the Advanced Meter Infrastructure (AMI), PGE pilot programs included staff from meter services, IT security/systems/applications, communication engineering, customer operations, distribution planning, and others. Developing SMEs in these and various areas subsequently saved customers money through the experience gained in the pilot programs. Employees were able to specify more detailed requirements for functionality, and – based on experience gained through pilot programs – detailed risk mitigation plans were formed to keep the large project's implementation on schedule and on budget. Conservatively, these two items alone reduced the cost of the AMI implementation by at least $20 million, far in excess of PGE's R&D annual budget.

Q. Please summarize why PGE is requesting an increase in R&D funding?

A. The electrical grid is undergoing a period of unprecedented change. Technologies are rapidly emerging that will allow us to operate a more efficient, resilient and safer grid. At the same time, increased penetration of distributed energy resources has brought with it a new set of challenges (e.g., integration of increasing amounts of distributed solar and battery storage, analyzing the hosting capacity of feeders, and extracting value from grid assets). The requested increase in expenditures for 2019 will fund projects that address the significant changes and new technologies facing PGE and the electric industry, and will allow PGE to stay abreast of changes and take full advantage of emerging technologies, thus delivering additional value to our customers.

B. Security

Q. Please describe the reasons for increasing security costs.

A. As discussed in UE 319, security costs are increasing due to new regulations affecting PGE's assets. Critical Infrastructure Protection regulation 014-1 (CIP-14) requires PGE to employ higher security measures at several of its transmission substations that "if rendered inoperable, or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection."[8] Additionally, Critical Infrastructure Protection regulation 002-5 (CIP-02) requires PGE to "identify and categorize

[8] See http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf for additional information.

BES [Bulk Electric System] Cyber Systems … for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliability operations of the BES."[9]

Q. What other trends are causing increased pressure on Corporate Security?

A. As Portland's homeless population has grown, PGE is seeing a significant increase in homeless camps and garbage left in and around PGE facilities, most notably at or near PGE substations. The number of calls to Corporate Security has also grown steadily in the past few years, with Corporate Security employees responding to approximately 22% more calls in 2017 compared to 2016. PGE's security staff is finding it very difficult to continue to meet the demands of this increased volume of physical security and safety concerns in a consistent manner.

Q. What progress has PGE made during 2017 to address the incremental workload?

A. PGE hired two people as 'CIP Alarm Monitors' in 2017. These positions are assigned to our WTC location and are responsible for monitoring physical security alarms and calls for assistance around the clock. PGE Exhibit 600 provides details on PGE's efforts to address increasing threats related to information security.

Q. Is PGE continuing to address these issues for 2018 and 2019?

A. Yes. While we hired two FTEs in 2017, we plan to hire three more FTEs in 2018 to fully comply with the above regulations and provide the necessary security coverage required for our assets. Two of these three additional FTEs will support PGE's alarm monitoring program, allowing for the transition and integration of physical security monitoring functions from an isolated operational area to the Integrated Security Operations Center.

[9] See http://www.nerc.com/files/cip-002-5.pdf for additional information.

This security is necessary for the protection of PGE's critical assets and our adherence to CIP-14 and CIP-02. Without real-time physical monitoring of the alarm system, PGE's ability to protect its critical assets will be flawed and incomplete. The other FTE will be hired to provide project management support and supervise the day-to-day operations of PGE's expanding physical security systems. Currently, there are only two Operations Specialists overseeing all incidents throughout our service territory. This additional FTE will enable the Specialists to focus on their core job duties, reduce unsustainable overtime and weekend work, and allow the Operations Specialist team to proactively meet growing regulatory requirements.

We also anticipate taking a proactive approach to security by addressing growing security concerns and changes to industry-wide security technology standards. Specifically, PGE will use outside services to provide project management support for replacing all standard locks at our substations and other field locations with electronic locks for enhanced security above the level of security required by CIP regulations. In addition, we will utilize outside services to evaluate our 15-year-old access control system and provide project management support for the development and scoring of a request for proposal to replace our current system, if necessary. If our current control panel were to break, we would be unable to buy a replacement due to the obsolescence of this technology. Therefore, evaluating our options for a new access control system is necessary for this aging technology.

C. Memberships

Q. In Section I above, you mention cost savings related to CEB/Gartner membership activities. Please describe the CEB/Gartner membership.

A. CEB/Gartner is a leading global research and advisory company. PGE's most recent contract allows for advisory services and counsel on corporate leadership, market insights, customer contact and communications, enterprise architecture, information risk management, recruiting and procurement, learning and development, strategic leadership, and customer experience and strategies.

Q. Describe the customer savings resulting from the centralization of various Individual Memberships to a Corporate Membership.

A. PGE recently grouped or centralized six CEB/Gartner individual membership subscriptions, when negotiating renewal of those memberships. In doing so, PGE negotiated a 10% company discount for an annual customer savings of approximately $42,000. PGE also negotiated for five additional areas of research, increasing its use of CEB/Gartner from four in 2017 to eleven being available for use in 2018 and 2019.

D. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains a prudent portfolio of insurance coverage, which we list and describe in PGE Exhibit 505 and confidential PGE Exhibit 506. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. We discuss these below, as well as address retained losses.

Q. What is PGE's forecast for insurance premiums for 2019?

A. As shown in Table 4 below, we expect total Property and Casualty premiums to be approximately $11.9 million, excluding 50% of non-primary layers of Directors and Officers (D&O) insurance. PGE expects the Property program premiums to increase at a 3.4% annualized level due to an increase in PGE's total insured value coupled with premium rate increases. The recent natural catastrophes seen in the third and fourth quarters of 2017 will most likely have a negative impact on future insurance renewals. Insurers are currently addressing losses from multiple hurricanes, earthquakes, and wild fires to identify and assess the extent of their exposures and the impacts on underwriting profits and policyholder surplus. Although we won't know the full effects until the first or second quarter of 2018, we expect that those with policies with insurance companies that have large natural catastrophe exposures and those that sustained losses during these recent natural catastrophe events could see large rate increases of 10% or greater. It has yet to be determined how renewal rates may be impacted for those insurance companies that were not directly affected by the recent storms or earthquakes, but have assets insured in higher risk natural catastrophe zones, such as PGE.[10] Should property insurers see similar losses in 2018 as were seen in 2017, there could be significant rate increases for premiums across all industries. Within the Casualty program, PGE expects slight increases in premiums in its General Liability, Workers' Compensation, and Cyber Liability coverages. Unforeseen severe Casualty losses would produce upward pressure on rates beyond the current forecast. Overall, we expect a 3.4% impact on premiums without taking into effect any unknown increases in premiums due to the natural disaster consequences discussed above.

Table 4
Insurance Premiums ($ millions)

Type of Loss	2017 Actuals**	2018 Forecast**	2019 Forecast	Annualized % Increase
Property	$5.57	$ 5.72	$6.02	4.0%
Casualty	$5.59	$5.69	$5.91	2.8%
Total*	**$11.16**	**$11.88**	**$11.93**	**3.4%**

** May not sum due to rounding.*
*** Premium amounts do not include membership credits or 50% of non-primary layers of D&O insurance*

[10] Cascadia Subduction Zone (assets West of the Cascade Mountain Range).

Q. What is PGE's forecast of expenditures for retained losses from 2017 to 2019?

A. As shown in Table 5 below, PGE's forecast of expenditures for retained losses increases by approximately 12.1% annually from 2017 to 2019, almost all of which occurs between 2017 and 2018. We discuss retained losses in more detail below.

Table 5
Retained Losses ($ millions)

Type of Loss	2017 Actuals	2018 Forecast	2019 Forecast	Annualized % Increase
Auto & General Liability	$1.14	$1.59	$1.59	18.3%
Workers' Compensation	$1.55	$1.75	$1.79	7.3%
Total*	**$2.69**	**$3.35**	**$3.38**	**12.1%**

** May not sum due to rounding*

1. Casualty

Q. What types of coverage are included in PGE's Casualty insurance program?

A. The eight components of PGE's Casualty insurance program are as follows:

- General & Auto Liability;
- D&O Liability;
- Fiduciary Liability;
- Workers' Compensation;
- Nuclear Liability;
- Cyber Liability;
- Aviation Hull & Liability (Including Unmanned Aircraft Systems); and
- Surety Bonds.

PGE Exhibit 505 describes each policy's purpose in more detail.

Q. Why is D&O insurance coverage important?

A. D&O liability insurance is important for the following reasons:

- It insulates customers and shareholders from having to shoulder the full financial impact in situations where PGE owes its directors and officers an indemnity obligation, or where PGE is a named party in securities litigation;
- The limits purchased are consistent with utility industry standard practices and reduce overall risk to both customers and shareholders;
- Maintaining the appropriate limit and type of D&O insurance is necessary to attract and retain qualified and competent directors and officers; and
- It shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business.

Q. Is PGE requesting 100% of the D&O premiums?

A. No. PGE is requesting 100% of the first layer of D&O coverage and 50% of non-primary layers. PGE made these adjustments to mitigate customer costs for insurance. Although we have made these reductions in this filing, we still believe that the inclusion of 100% of D&O insurance premiums in customer prices is appropriate.

Q. Why does PGE purchase Workers' Compensation insurance?

A. The State of Oregon requires PGE to maintain coverage to provide employees who are injured on the job with insurance coverage that will compensate them for lost wages, medical care, and if necessary, vocational rehabilitation.

2. <u>Retained Losses</u>

Q. Please explain Retained Losses.

A. Retained losses are the portion of any claim falling within PGE's self-insurance retentions for its Auto Liability, General Liability, and Workers' Compensation exposures that are frequent and predictable. Simply put, retained losses are the amounts borne by PGE before any insurance recovery.

Q. What is the forecasted increase in annual claim expenditures for retained losses in Workers' Compensation and Auto and General Liability?

A. As shown in Table 5 above, PGE expects annual cash expenditures for retained losses for Workers' Compensation and Auto and General Liability claims to increase by an annual average of 12.1% from 2017 to 2019. In 2018 and 2019, PGE's annual expenditures are budgeted at the expected level, based on the actuarial projections and anticipated claims. PGE budgets for Auto and General Liability retained losses based on actuarial projections. Workers' Compensation retained losses are budgeted by reviewing PGE's prior year's claim experience and adjusted as needed for new and anticipated claims costs.

III. Summary

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve PGE's forecast of $180.8 million in A&G costs in the 2019 test year. This represents a $4.7 million increase from 2017 actuals due primarily to increases in employee benefits (i.e., health care and dental premiums), human resources, and R&D costs.

Absent cost increases for employee benefits and IT (plus the increase associated with Public Utility Commission of Oregon (OPUC) fees, PGE has reduced its 2019 A&G forecast with an overall annualized 5.4% cost decrease from 2017.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
501	Summary of A&G Costs and FTEs
502	UE 319, PGE Exhibit 600
503	2019 R&D Proposed Projects
504	Data Analytic & Visualization POC
505	Insurance Policies List
506C	Summary of Insurance Costs

A&G Summary

Category	Costs 2015 Actuals	Costs 2016 Actuals	Costs 2017 Actuals	Costs 2018 Budget	Costs 2019 Forecast	Costs 2017 to 2019 $ Delta	Costs 2017 to 2019 Annual %	FTEs 2015 Actuals	FTEs 2016 Actuals	FTEs 2017 Actuals	FTEs 2018 Budget	FTEs 2019 Forecast	FTEs 2017 to 2019 $ Delta	FTEs 2017 to 2019 Annual %
Major Functional Areas														
Facilities and General Plant Maintenance	4.8	5.5	5.9	6.7	6.3	0.4	3.8%	28.2	23.3	23.2	23.6	23.6	0.5	1.0%
Accounting/Finance/Tax	9.2	9.2	10.1	11.2	11.5	1.5	7.0%	65.3	66.8	68.8	75.9	76.1	7.4	5.2%
HR/Employee Support (net of capital allocs.)	9.0	9.8	11.3	13.0	13.6	2.3	9.7%	111.1	114.0	119.1	133.1	133.3	14.2	5.8%
Insurance / I&D	12.1	11.5	12.3	12.2	12.2	-0.1	-0.5%	6.9	7.0	6.9	7.0	7.0	0.1	0.4%
Legal	5.0	5.0	6.1	5.3	5.5	-0.5	-4.6%	22.0	21.6	22.3	25.0	25.0	2.6	5.8%
Regulatory Affairs	2.8	2.5	2.9	3.5	3.6	0.7	12.0%	31.2	28.9	29.3	34.0	34.0	4.6	7.6%
Corporate Governance	4.5	4.6	5.1	5.5	5.6	0.5	4.7%	17.4	18.2	18.4	19.3	19.3	0.9	2.5%
Business Support Services	2.5	2.4	2.8	2.6	2.6	-0.1	-2.6%	7.0	5.1	2.0	3.5	3.5	1.5	33.6%
Environmental Services	2.0	3.1	2.3	2.2	2.3	0.0	-0.2%	0.0	0.0	0.0	0.0	0.0	0.0	
Corporate R&D	1.4	2.0	1.8	2.2	3.2	1.4	32.3%	1.2	1.0	0.2	0.0	0.0	-0.2	-53.3%
Contract Services/Purchasing	1.6	1.5	2.1	2.2	2.3	0.2	5.3%	21.3	20.2	20.1	22.8	22.8	2.7	6.6%
Security and Business Continuity	2.2	2.2	2.4	2.9	3.0	0.6	12.1%	15.0	14.0	15.1	19.9	19.9	4.8	14.8%
Corp Communications/Public Affairs	2.0	2.2	2.5	2.3	2.4	-0.1	-2.3%	24.3	25.0	25.4	27.1	27.1	1.7	3.3%
Hydro Licensing and Support	0.1	0.1	0.1	0.1	0.1	0.0	12.8%	0.0	0.0	0.0	0.0	0.0	0.0	
Performance Management	1.3	1.3	1.2	1.8	1.9	0.7	27.4%	10.9	12.0	11.7	11.3	11.1	-0.6	-2.8%
Governmental Affairs	1.2	1.2	1.2	1.2	1.3	0.1	3.2%	8.8	10.1	9.7	11.1	11.1	1.4	7.0%
Subtotal	61.5	64.0	70.0	74.7	77.5	7.5	5.2%	370.5	367.2	372.1	413.6	413.9	41.7	5.5%
Other A&G Costs														
IT: Direct & Allocated	11.3	12.1	12.0	12.4	15.5	3.4	13.4%	234.8	272.4	304.3	341.7	321.2	16.8	2.7%
Corporate Cost Reductions	0.0	0.0	0.0	-2.1	-2.1	-2.1					-19.6	-38.9	-38.9	
Other Membership Costs	2.9	3.1	3.2	3.5	3.6	0.4	6.0%							
Incentives	20.9	21.6	28.2	30.6	13.0	-15.2	-32.1%							
Severance	-0.1	1.6	1.5	1.3	1.3	-0.2	-7.0%							
Regulatory Fees	6.4	6.7	7.8	7.7	7.9	0.1	0.4%							
General Plant Maint.	2.6	2.6	2.4	2.8	2.9	0.5	9.8%							
Total PTO to A&G	5.9	4.2	6.3	6.3	6.6	0.3	2.4%							
Total Labor Loadings to A&G	0.0	0.0	0.0	0.0	0.0	0.0	-42.3%							
Benefits (net of capital allocs.)	54.3	51.8	49.2	58.7	62.6	13.4	12.8%							
Corp Allocations	-3.8	-5.4	-6.4	-8.1	-9.7	-3.4	23.7%							
Revolver Fees, Margin Net Int., & Broker fees	3.0	1.9	1.8	2.1	1.8	0.0	-0.9%							
Subtotal	103.2	100.2	106.1	115.1	103.3	-2.8	-1.3%							
TOTAL A&G	164.7	164.2	176.1	189.9	180.8	4.7	1.3%	605.3	639.6	676.5	735.7	696.1	19.7	1.4%

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Alex Tooman. I am a Project Manager for PGE. My qualifications appear at the end of PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $172.1 million in administrative and general (A&G) costs in 2018 and compare it to 2016 actuals of $170.9 million.

Q. What functions are classified as A&G and what are the costs of those functions?

A. We classify as A&G those functions that support PGE's direct operations to deliver electric power to customers, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT). We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the FERC definition of A&G.[1] PGE Exhibit 601 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2014 (actuals) through 2018 (test year forecast). Table 1 below summarizes the major A&G costs by functional area.

[1] FERC defines administrative and general expenses as those that fall within FERC accounts 920 through 935.

Table 1
A&G Costs by Major Functional Area ($ millions)

Major Functional Areas	**2016 Actuals**	**2018 Forecast**	**Delta***
Facilities	$5.5	$7.0	$1.5
Accounting/Finance/Tax	$9.9	$11.3	$1.4
HR/Employee Support	$9.8	$13.4	$3.6
Insurance, Injuries and Damages, etc.	$11.5	$12.2	$0.8
Legal	$10.0	$5.4	($4.6)
Regulatory Affairs/Compliance	$2.6	$3.4	$0.8
Corporate Governance	$4.6	$5.4	$0.8
Business Support Services	$2.4	$2.8	$0.3
Environmental Programs	$4.4	$2.2	($2.1)
Corporate R&D	$2.0	$3.0	$1.0
Contract Services/Purchasing	$1.4	$1.4	$0.0
Security and Business Continuity	$2.2	$2.9	$0.7
Corp Communications/Public Affairs	$2.2	$2.4	$0.2
Load Research	$0.1	$0.0	($0.1)
Hydro Licensing	$0.1	$0.1	$0.0
Performance Management	$1.3	$2.1	$0.8
Governmental Affairs	$1.2	$1.2	$0.0
Total for Major Functional Areas*	**$71.0**	**$76.3**	**$5.2**
IT: Direct and Allocated	$12.1	$13.4	$1.3
Labor Cost Adjustment	$0.0	($3.6)	($3.6)
Membership Costs	$3.1	$3.6	$0.5
Incentive Plans (net of capital allocations)	$21.6	$12.6	($9.0)
Severance	$1.6	$1.3	($0.3)
Regulatory Fees	$6.7	$8.7	$2.0
General Plant Maintenance	$2.6	$2.9	$0.3
Net PTO	$4.4	$6.3	$2.0
Net Loadings	$0.0	$0.0	$0.0
Benefits (net of capital allocations)	$51.8	$57.7	$5.9
Corporate Allocations	($5.7)	($8.7)	($3.0)
Revolver Fees, Margin Net Int., Broker Fees	$1.9	$1.8	($0.1)
Total Other A&G Costs*	**$99.9**	**$95.8**	**($4.1)**
Total A&G*	**$170.9**	**$172.1**	**$1.2**

** May not sum due to rounding.*

Q. What are the primary drivers for the increase in A&G costs from 2016 to 2018?

A. Most of the increases in A&G costs from 2016 to 2018 are attributable to three primary drivers: 1) Benefits, as discussed in PGE Exhibit 400, are largely driven by health care costs. 2) Security and emergency management, driven by the growing recognition of the potential for detrimental events and PGE's and our regulating bodies increasing emphasis on protecting critical energy infrastructure. 3) Human Resources, driven by PGE's continued efforts to reduce workplace injuries and move to best in class in workplace safety, along with increased demands on PGE's staffing and training departments. While we can and do actively manage costs associated with these drivers, they are, to some extent, external to PGE and reflect larger market conditions and/or regulatory requirements beyond our control.

Q. Will you be discussing any additional A&G related items?

A. Yes. In addition to the drivers highlighted above, we will discuss the following:

- Costs associated with PGE's corporate research and development (R&D) activities;
- Increasing membership costs for PGE's participation in the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group;
- Increases in labor and outside services for Accounting and Finance Services;
- The current insurance environment, as prudent insurance coverage is integral to PGE's operations; and
- PGE's forecast of A&G related environmental costs and their relationship to PGE's pending Environmental Remediation Costs Recovery Adjustment, PGE Tariff Schedule 149, (Docket No. UM 1789).

Q. How is the remainder of your testimony organized?

A. After this section, we have four sections:

- Section II: Primary A&G Cost Increases;
- Section III: Other Items;
- Section IV: Environmental and Licensing Services; and
- Section V: Summary.

II. Primary A&G Cost Increases

A. Benefits

Q. By how much do you forecast benefit costs to increase from 2016 to 2018?

A. The increase in net benefit costs from 2016 to 2018 is approximately $5.9 million. These costs include such items as health and dental plans, 401(k) plan, pension costs, and employee life and disability insurance.

Q. What accounts for this increase?

A. The primary driver of the increase in benefit costs is health-care costs, which reflect inflation and other cost pressures. PGE Exhibit 400 explains in greater detail how the compensation and benefits-related costs are affected by these increases and how PGE must address them to remain competitive in a market for specialized and qualified labor. Please note that the benefit amounts in Table 1 above represent the "net" changes within A&G.[2] PGE Exhibit 400 explains the gross corporate forecast for these costs.

B. Security and Emergency Management

Q. Please explain the cost increase for Business Continuity and Emergency Management (BCEM) and Security.

A. PGE's costs for BCEM are forecasted to increase from approximately $0.8 million to $1.2 million from 2016 to 2018, while security costs are expected to increase from approximately $1.4 million to $1.7 million over the same period. As discussed in PGE's 2016 general rate case (UE 294, Exhibit 600), the projected increase to BCEM costs is based on the continued development and completion of a BCEM roadmap. The roadmap establishes the activities PGE needs to perform to achieve a target level of regional

[2] Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects, service providers, and "below-the-line" activities.

preparedness and resilience among PGE's primary departments/systems. The increase to security costs is due largely to increasing regulation and the expanding footprint of PGE's physical locations.

Q. What is the history and purpose of the BCEM department?

A. PGE established the BCEM department in 2007 to strengthen capacities and capabilities for the preparation, mitigation and response to significant emergency incidents that may adversely affect service to customers, company assets, and employees. This includes providing planning, training and exercise support to recover critical functions as quickly as possible, in compliance with all regulatory requirements. This department establishes business continuity and emergency management plans and procedures; conducts risk and business impact assessments; develops training programs and materials; and establishes and operates emergency operations center functions and facilities needed to effectively prepare for, respond to, and recover from, a variety of emergency incidents.

Q. You stated that PGE needs to meet a "target level of resilience". Please explain.

A. Resilience is the ability of a department to quickly restore its performance to an operational level after some form of detrimental event. By detrimental event, we are referring to natural events (e.g., major earthquake or flood), technological events (e.g., a significant system or plant failure due to mechanical or physical issues), or man-made (accidental or intentional) events (e.g., a successful cyber-attack or act of terrorism). In order to evaluate a department's resilience, the BCEM roadmap establishes a timeline for each primary department/system to undergo the following cycle:

- Develop plans to restore operations;
- Train employees on restoration procedures;

- Perform exercises to test employees; and
- Evaluate performance.

Once established, this cycle is an annual mechanism that will continue to strengthen PGE's capacities and capabilities for emergency response.

Q. Has PGE expanded its corporate resiliency and emergency preparedness efforts?

A. Yes. Through 2014, BCEM operated with only four or less FTEs (with approximately two of these FTEs for support and administration). This limited the number of areas within PGE that BCEM was able to support with its full range of duties. As the awareness of and potential for detrimental events continue to increase, PGE continues to expand its BCEM efforts. To this end, we hired three additional FTEs between 2015 and 2016 to help with the company-wide implementation of key initiatives established in the BCEM roadmap. For 2017 and 2018, BCEM is increasing outside services support in order to continue our efforts in meeting the annual elements identified within the roadmap's timeline. This effort is also based in part on The Oregon Resilience Plan,[3] which recommends that "Energy sector companies should institutionalize long-term seismic mitigation programs and should work with the appropriate oversight authority to further improve the resilience and operational reliability of their Critical Energy Infrastructure (CEI) facilities" (page 175).[4]

Q. What are some recent activities in which PGE's BCEM department has been involved to further PGE's corporate resiliency and emergency preparedness?

A. PGE was very active during 2016 in efforts to assess our corporate resiliency and emergency responsiveness to a Cascadia Subduction Zone earthquake and tsunami. In particular, PGE

[3] Issued by the Oregon Seismic Safety Policy Advisory Commission to the Oregon State Legislature in February 2013.
[4] The Oregon Resilience Plan is available at: http://www.oregon.gov/OMD/OEM/osspac/docs/Oregon_Resilience_Plan_Final.pdf

participated in the U.S. Department of Energy's Clear Path IV exercise and closely followed the region-wide Cascadia Rising 2016 functional exercise. Based on these exercises, the BCEM team plans to expand its core planning related to regional disasters, with improvements to fueling, staging and communications.

Q. Please describe the reasons for increasing security costs.

A. PGE's security costs are increasing due primarily to the expanding footprint of PGE's system and the addition of new regulations affecting some of PGE's substations. Recent and upcoming additions to PGE's footprint include two new plants at the end of 2014, Carty in 2016, and a number of smaller substation projects that will be completed over the next one to two years. Additionally, Critical Infrastructure Protection regulation 014-1 (CIP-14) has directed PGE to employ higher security measures at several of its transmission substations that "if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection."[5]

Q. What other trends are putting increased pressure on Corporate Security?

A. As Portland's homeless population has grown, PGE is seeing a significant increase in homeless camps in and around PGE facilities, most notably at or near PGE substations. Consequently, PGE's Corporate Security employees are responding to an increased volume of safety and security concerns related to these camps. PGE's current security staff cannot continue to meet the demands of this increased volume in a consistent manner.

Q. How is PGE addressing these issues?

A. In order to provide effective security coverage for our expanding footprint of assets, and to address the increased security concerns from our community, PGE is adding three FTEs between 2017 and 2018. One additional FTE will be hired to provide project management

[5] http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf

support for CIP-14 and to lead the day-to-day operations of PGE's expanding physical security systems.

C. Human Resources

1. Safety

Q. Please discuss PGE's company-wide safety focus.

A. PGE has been and continues to be committed to providing a safe and healthy place for employees, customers, and the public. Safety is a core value that PGE integrates into everything we do. We believe most hazards can be identified and effectively controlled or eliminated to prevent incidents and their consequences. Thus, it is important that we focus on continuously improving our safety performance, to meet our goal of an injury-free workplace.

Q. Has PGE's safety record shown improvement?

A. Yes. There are a number of signs indicating that PGE's record on safety is improving. Most notably, PGE has seen a decrease in workplace accidents, as evidenced by a 23 percent overall decrease in Occupational Safety and Health Administration (OSHA) "recordable" accidents since 2014. [6]

Q. What additional steps is PGE taking to improve safety?

A. In order to increase the effectiveness of PGE's safety culture and continue to reduce injuries and incidents, PGE has developed a comprehensive five-year safety strategy plan. Additionally we are adding one FTE in 2017 and one FTE in 2018 that will help address the following:

[6] OSHA defines a recordable accident as any work-related injury or illness that causes a fatality, unconsciousness, lost work days, restricted work activity, job transfer or medical care beyond first aid.

- A greater level of support in auditing PGE's safety programs, providing technical writing support and general support of new and existing safety programs and practices;
- Thorough administrative and analytical support of PGE's safety reporting system to harness the system benefits of improved safety metrics analysis, incident reporting, and anonymous "near-miss" reporting;
- Support for an increased level of safety and work practices training; and
- Implementation and increased focus on specialized employee and contractor safety and injury prevention programs, such as:
    a. The MoveSmart program to reduce sprains and strains;
    b. The Early Injury Intervention Effort for preventative self-treatment strategies;
    c. The Safety Leadership Development Program to provide management and safety mentors the tools to promote safe practices; and
    d. The Contractor Safety Program to promote a safety culture throughout PGE's operations.

A copy of the five-year safety strategy map outlining the above activities is included in the work papers for PGE Exhibit 600.

2. Support Services

Q. How much are training and staffing services costs projected to increase for 2018?

A. PGE's costs for these support services are forecasted to increase from approximately $3.6 million to $5.2 million from 2016 to 2018.

Q. Please describe the drivers behind PGE's increase in staffing.

A. PGE continues to see an increase in the volume of hiring, placing increased demands on current staff, who are now operating beyond their capacity. As shown in Table 2 below, the actual and projected number of annual job requisitions staffing services has filled since 2014 is increasing substantially. This current and projected higher level of hiring reduces staffing services effectiveness and cannot be maintained at the current staffing levels. Additionally, with a high number of senior professionals nearing retirement at PGE (and throughout the utility industry), the demands for skilled utility professionals has increased. At the same time, an improved economy has increased the difficulty and time requirements involved to recruit, hire, and retain these in-demand professionals.[7]

Table 2
Filled Position Requisitions

Year	Filled Requisitions
2014	638
2015	838
2016	930
2017*	1,200
2018*	950

*Estimated

Q. Are there other pressures increasing the workload for PGE's Staffing Services?

A. Yes. Along with the pressures associated with the overall increases in hiring, PGE is hiring more PGE employees, rather than outside contractors, for recent capital project work. Specifically, PGE is increasing the level and pace of transmission and distribution (T&D) maintenance and reliability work throughout our system. To perform this work, PGE is relying more on internal PGE labor as opposed to the outside services traditionally used for large-scale generation projects. PGE decided on this strategy primarily due to the scarcity of qualified labor, the high turnover rate of contract labor, and commitment to the projects, which are long-term in nature. However, using more of an internal, rather than external

[7] According to the Bureau of Labor Statistics, as of December 2016, Oregon's unemployment rate was 4.6%. https://www.bls.gov/eag/eag.or.htm#eag_or.f.p

workforce does place additional strain and workload on our Staffing Services department. PGE Exhibits 400 and 800 provide more detail on this hiring strategy.

Q. How is PGE addressing these pressures?

A. To address the increased hiring pressures and maintain recruiting competitiveness, Staffing Services is adding three and a half FTEs between 2017 and 2018. Staffing Services has also increased its budget for outside services to assist with the recruitment process. These additional FTEs will allow Staffing Services to meet the increased demand in hiring, while maintaining its current time-to-fill-ratio. Additionally, Staffing Services will continue supporting management in its selection process and engage in proactive recruiting strategies such as career fairs, data-driven analytics, college internships, line pre-apprenticeship programs, and social media outreach.

Q. How have PGE's training needs changed over the last couple of years?

A. The demands for training continue to increase as PGE continually implements and integrates new systems and programs. At the same time, the electric utility industry continues to evolve, leading to a greater complexity of systems, processes, and regulatory requirements. Due to this complexity, and for program consistency, PGE has begun centralizing the majority of our training programs in order to gain maximum efficiency of effort. This centralization effort also allows PGE's functional area subject matter experts to focus on their job-specific requirements. As such, with this centralization of both instructor-led and computer-based training, PGE's training department is adding three FTEs in 2018 and increasing its contract labor budget. These additional FTEs are in support of the centralization effort along with the following increases to training demands:

- Additional pre-apprenticeship program offerings and continued growth associated with the existing apprenticeship program;
- New curriculum development including: safety leadership, service design management, and soft tissue injury prevention;
- Increasing mandatory regulatory training and development;
- Additional Generation Excellence training;
- New engineer curriculum for Transmission, Distribution and Generation engineers; and
- Company-wide skill track creation and maintenance.

III. Other Items

A. Research and Development

Q. Why does PGE engage in Research and Development (R&D) activities?

A. PGE conducts R&D on behalf of customers to both preserve and improve system reliability and at the same time to anticipate changes that could profoundly alter the grid.

Q. What are PGE's forecasted 2018 costs for PGE's corporate R&D activities?

A. For 2018, we forecast approximately $3.0 million in R&D expenses, of which approximately $2.8 million is for specific R&D projects and the remainder is for administrative expenses. This reflects an increase of approximately $1.0 million over 2016 actuals. PGE's increased spending represents numerous selected projects that will address the significant changes and new technologies facing PGE and the electric industry. These R&D projects primarily relate to Smart Grid (SG) applications, system reliability (SR), renewable power (RP), operational efficiency (OE), energy storage (ES), and system resiliency (SY). These R&D projects directly contribute to PGE's ability to evaluate and deploy technologies and resources that will benefit our customers for decades to come; they help shape Oregon's energy future to conform to customer priorities for an even more reliable, sustainable and smarter electric power system. Table 3 below provides a listing of the 2018 R&D project categories and number of expected projects within each category. We also provide a complete listing with descriptions and project benefits in PGE Exhibit 604.

Table 3
Topical Summary of 2018 R&D Applications

	Category	Approx. Cost	Number of Projects
SG	Smart Grid	$925,300	18
SR	System Reliability	$578,000	10
RP	Renewable Power	$535,000	7
OE	Operational Efficiency	$430,000	7
ES	Energy Storage	$210,000	4
SY	System Resiliency	$75,000	2
	Total	**$2,753,300**	**48**

Q. Please summarize why PGE is requesting an increase in R&D funding.

A. The U.S. electrical grid is aging and changing in very substantial ways. It is increasingly clear that central station power generation and the "one-way" power flow that it fostered will slowly be replaced with distributed forms of power generation, including solar, biomass, small/low head hydrokinetic devices, and wind resources. The arrival of these smaller sources of power generation will by necessity, require "bi-directional" power flow that can emanate from residential and commercial structures and even PGE electrical substations. Smart AC/DC inverters for autonomous control of batteries and distributed generation devices, smart switches capable of sectionalized isolation and heightened concern for cybersecurity will all have important roles going forward. It is important that PGE, for safety and efficient application, understands how this new and substantial transformation will unfold. This means that PGE should study now the possible implications and preparations needed to accommodate industry advances.

Q. What is PGE doing to pursue R&D in a cost effective manner?

A. PGE recently assessed its R&D cost effectiveness using two principal approaches: 1) participation in a nationwide benchmarking study and 2) limiting overhead cost.

Q. Describe the Benchmarking Study results as they pertain to PGE's R&D spending.

A. PGE and 48 utilities voluntarily participated in a 2016 R&D Benchmarking Survey conducted by the Electric Power Research Institute (EPRI). In that study, PGE's annual R&D expenditure of $2 million was the fifth lowest out of the 12 participating western utilities. PGE also ranked below average on a revenue-adjusted basis, when compared to all 48 utilities.[8] On absolute and relative bases, PGE's R&D expenditure is low when compared to western utilities and low on a revenue-normalized basis compared to 48 U.S. utilities.

Q. Describe the Benchmarking Study results as they pertain to R&D administrative costs.

A. PGE limits its overhead costs in pursuing R&D even in the face of increased funding and program efforts. PGE's FTEs for R&D administration have decreased from 1.7 in past years to only 1.0 for 2018. The EPRI R&D benchmarking study showed that for investor owned utilities the average number of R&D FTEs was 1.3. The fact that PGE's FTE levels associated with R&D administration are lower than the utility average validates the efficiency of PGE's R&D program.

Q. Does PGE engage research partners?

A. Yes. PGE leverages many of its R&D projects financially by working with other utilities as well as universities to co-sponsor and/or share R&D. In doing so, PGE and its customers receive 100% of the benefits for a fraction of the overall research costs; often receiving useful knowledge much earlier than if we did not contribute or otherwise engage with research partners. PGE's university partners view PGE's R&D dollar contributions as part of required matching funds for much larger federal or other institutional grants, and would

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8 Out of 48 utilities, PGE ranked 20th from low to high when R&D expense was normalized to revenue, and was about 75% of the overall average of 0.21% of R&D expense as a percent of revenue.

otherwise be unable to receive the necessary funding without PGE's co-sponsorship. PGE will work with several universities on shared projects that support unique, regional renewable power research that include wave, wind, solar, and CO_2 capture, as well as sequestration through torrefied biomass fuel used to displace coal. PGE will continue to co-sponsor projects with Portland State University, Oregon State University, Washington State University, University of Oregon and Oregon Institute of Technology.

Q. How have PGE's customers benefited from R&D in the past?

A. PGE recently completed a 20-year retrospective report covering its R&D activities over the period 1994-2014. An experienced consultant, funded by PGE, performed seven detailed case studies to assess value and benefit to customers. Value determinations involved both operating savings and avoided capital expenditures (netting these against operating costs and capital costs). The net value for these seven case studies were then compared to the base R&D costs that made these projects possible. The comparison showed a $37 to $1 net value over the original R&D cost. PGE's work papers for Exhibit 600 include this 20-year report.

Q. What is PGE's plan for 2018 Smart Grid projects?

A. PGE has identified 48 total projects for 2018 of which 18 relate to Smart Grid (or "Integrated Grid") topics. Smart Grid work comprises 38% of the total project numbers and 34% of the 2018 R&D funding request. Of the 18 Smart Grid projects, 12 are primarily on the behalf of residential and commercial customers. This is timely due to the influx of electrical devices that are rapidly becoming "smart" and finding their way into the "internet of things" ecosystem. Examples include more granular and autonomous energy controls at the device level (e.g., water heaters, thermostats, and lighting of all types). The energy control devices, when aggregated appropriately, may be harnessed to benefit the power grid, and thus customers in terms of load shifting and demand response support, which ultimately can lower operational costs.

Q. Please summarize PGE's other 2018 R&D efforts and the reasons behind these efforts.

A. PGE's 2018 R&D effort also supports System Reliability, Renewable Power and Operational Efficiency and these proposed R&D projects are in proportions varying from 15% to 20% of the 2018 R&D effort. System Reliability and Operational Efficiency work focuses on PGE's established infrastructure (e.g., power plants, poles, wires and substations), making it more reliable, safe and efficient. R&D in these areas, especially when coupled with EPRI programs, help PGE to keep abreast of industry best practices and lessons learned in power generation and transmission and distribution areas. PGE R&D projects include twelve EPRI programs, and are part of the 24 projects that form the three areas of interest. Finally, there are four Energy Storage and two System Resiliency projects targeted for 2018 R&D efforts. Due to cost, energy storage options such as batteries continue to hover at the edge of practicality; nonetheless, PGE needs to be aware of advances in this area especially as it relates to system resiliency support in the event of large, disruptive events such as a Cascadia Subduction Zone earthquake. In these types of emergencies, energy storage capability, whether stationary or mobile such as in electric vehicles, can play a meaningful role in recovery and restoration efforts. PGE will continue its efforts to validate use cases for the five MW, 1.25 MWh lithium ion battery inverter system (BIS) at its Salem Smart Power Center. This substantial BIS was highly subsidized by the United States Department of Energy as part of its five-year Pacific NW Smart Grid Demonstration Program of which PGE was a participant from inception.

B. Memberships

Q. Please explain the increase in membership expenses from 2016 to 2018.

A. PGE's membership costs have increased by approximately $475 thousand from 2016 to 2018. This increase is largely attributed to PGE's mandatory participation in WECC and PEAK Reliability (PEAK), projected at $2.3 million in 2018, compared to $2.0 million in 2016.

Q. What process does PGE use to budget for annual WECC and Peak expenses or fees?

A. PGE bases its budget for 2017 and 2018 on the estimated amounts provided to PGE from WECC and PEAK that are included in their annual business plan and budget documents.

Q. What reasons do WECC and PEAK provide for the increased fees?

A. According to annual budget documents, both WECC and PEAK are increasing membership fees due primarily to rising personnel expenses and increases in fixed asset additions.

Q. Have there been any other significant increases in membership costs?

A. Yes. PGE's share of membership in the Northern Tier Transmission Group (NTTG) will increase by approximately $100,000 from 2016 to 2018.

Q. What is the NTTG?

A. The NTTG is comprised of transmission providers and customers that actively purchase and sell transmission capacity on the Northwest and Mountain States grid. The group coordinates individual transmission systems planning of their high-voltage transmission network to meet and improve transmission services that deliver power to customers. NTTG coordinates its planning activities with the three other Regional Transmission organizations in WECC (Columbia Grid, West Connect, and CAISO). PGE participates in the NTTG along with a number of other utilities, transmission owners, and stakeholders in the region.

Q. What reasons does NTTG provide regarding their fee increase?

A. Beginning in 2017, NTTG anticipates a sizable increase in consulting and legal fees regarding potential modifications to Federal Energy Regulatory Commission (FERC) Order No. 1000, which establishes the requirements for transmission planning.[9] NTTG also anticipates increased modeling and analysis to support the development and implementation of the WECC Anchor Data Set (ADS). Benefits of the ADS include establishing a common starting point for all production cost model and power flow datasets, produced by WECC and the Planning Regions, which will result in aligned assumptions used in the planning model development for The Transmission Expansion Planning Policy Committee and the Western Planning Regions.

Q. Has PGE included an adjustment to Memberships in this case?

A. No. In the past PGE has included a pre-filing adjustment to remove costs associated with non-utility memberships and lobbying. However, because these costs are identifiable when PGE is charged for them, PGE now records and budgets for them in applicable, non-utility accounts that are not included in this filing.

C. Accounting and Finance Services

Q. How much are costs in PGE's Accounting and Finance organization projected to increase for 2018?

A. PGE's costs for these services are forecast to increase from approximately \$9.9 million to \$11.3 million from 2016 to 2018.

Q. Please briefly describe the drivers behind this increase.

A. This increase is due to the addition of four FTEs needed to support various functions in the Accounting and Finance area along with an increase in outside services support.

[9] See https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp for more detail on FERC Order No. 1000.

Q. Why does Accounting and Finance require four additional FTEs?

A. PGE is adding four additional FTEs to help in the following areas:

- Supply Chain – We are adding two FTEs to Supply Chain Services to address the current lack of resources available for supporting increased activity in both purchasing and vendor management activities due to centralization and streamlining of all supply chain functions.
- Accounts Payable/Receivable (AP/AR) – One FTE is being added to the AP/AR department to provide additional compliance support for PGE's purchasing card (P-card) program. After auditing its P-card program, PGE determined that additional oversight was required to improve compliance management and provide timely reviews of expenditures. Doing this will reduce PGE's potential exposure to unauthorized/fraudulent charges. Additionally, compliance responsibilities will increase as PGE increases its ratio of P-card usage versus check or Automated Clearing House transactions, in order to reduce the average per-transaction charge.
- Corporate Finance – We are adding one FTE to provide company-wide Enterprise Risk Management (ERM) support. PGE does not currently have a full-time resource dedicated to ERM activities. This position will work throughout the organization with subject-matter experts to identify and assess particular events or circumstances in terms of their likelihood and magnitude of detrimental impact to PGE. The next steps after identification are to develop a response strategy and to monitor future progress.

Q. Why are outside services increasing for Accounting and Finance?

A. The outside services increase is largely attributable to increases in PGE's auditing costs for 2017 and 2018 as compared to 2016. Beginning in 2017, PGE's audit services increased their fees by approximately $100,000. Additionally, PGE is forecasting an increase of approximately $200,000 for additional auditing hours needed to identify and review the accounting and controls impacts related to a number of current and future accounting changes. Some of these changes include: 1) the implementation of PGE's new Customer Information System; 2) new lease accounting rules issued by the Financial Accounting Standards Board (FASB); and 3) new revenue recognition accounting standards issued by the FASB.

Q. Have outside services increased in any other accounting services areas from 2016 to 2018?

A. Yes. There is also an apparent increase in the budget for tax consulting services. However, this is due to an unusually limited need for these services during 2016, resulting in lower than average costs. If looking across the period of 2013 through 2016, PGE's tax department spent an average of approximately $480,000 per year for tax consulting services. This compares to the 2018 forecast of approximately $206,000. With a very active legislative session in 2017, which includes a large number of tax proposals, PGE fully expects to spend its consulting services budget for both 2017 and 2018.

D. Insurance

Q. What types of insurance coverage does PGE maintain?

A. PGE maintains a prudent portfolio of insurance coverage, which we list and describe in PGE Exhibit 602 and confidential PGE Exhibit 603. In general, the insurance coverage maintained by PGE falls into two broad programs: Property and Casualty. We discuss these below as well as address retained losses.

Q. What is PGE's forecast for insurance premiums for 2018?

A. As shown in Table 4 below, we expect total Property and Casualty premiums to be approximately $11.4 million, excluding 50% of non-primary layers of Directors and Officers (D&O) insurance. PGE expects the Property program premiums to increase slightly due to an increase in PGE's total insured value coupled with a mild annual 2.0% rate increase. The decrease in Property premiums from 2016 to 2018, shown in Table 4 below, show a decrease because there was a limited-time builder's risk policy extension in 2016. If the builder's risk policy is factored out ($0.35 million), premiums show a slight average annual increase of 2.5%. Within the Casualty program, PGE expects slight increases in premiums in its General Liability, Workers' Compensation and Cyber Liability coverages. Unforeseen severe Casualty losses would produce upward pressure on rates beyond the current forecast. Overall, we expect a mild 1% impact on premiums.

Table 4
Insurance Premiums ($ millions)

Type of Loss	2016 Actuals**	2018 Budget**	Annualized % Increase
Property	$5.93	$5.88	(0.5)%
Casualty	$4.86	$5.13	2.7%
Total*	**$10.79**	**$11.38**	**1.0%**

** May not sum due to rounding.*

*** Premium amounts do not include membership credits or non-primary layers of D&O insurance*

Q. What is PGE's forecast of expenditures for retained losses from 2016 to 2018?

A. As shown in Table 5 below, PGE's forecast of expenditures for retained losses increases by approximately 14.1% annually from 2016 to 2018. We discuss retained losses in more detail below in Section 2.

Table 5
Retained Losses ($ millions)

Type of Loss	2016 Actuals	2018 Budget	Annualized % Increase
Workers' Compensation	$1.57	$1.75	5.8%
Auto & General Liability	$1.19	$1.83	24.2%
Total*	**$2.75**	**$3.58**	**14.1%**

** May not sum due to rounding*

1. Casualty

Q. What types of coverage are included in PGE's Casualty insurance program?

A. The eight components of PGE's Casualty insurance program are as follows:

- General & Auto Liability
- Directors and Officers (D&O) Liability)
- Fiduciary Liability
- Workers' Compensation
- Nuclear Liability
- Cyber Liability
- Aviation Hull & Liability
- Surety Bonds

PGE Exhibit 602 describes each policy's purpose in more detail.

Q. Why is D&O insurance coverage important?

A. D&O liability insurance is important for the following reasons:

- It insulates customers and shareholders from having to shoulder the full financial impact in situations where PGE owes its directors and officers an indemnity obligation or where PGE is a named party in securities litigation;
- The limits purchased are consistent with utility industry standard practices and reduce overall risk to both customers and shareholders;

- Maintaining the appropriate limit and type of D&O insurance is necessary to attract and retain qualified and competent directors and officers; and
- It shields PGE's directors and officers against normal, but sometimes significant, risks associated with managing the business.

Q. Is PGE requesting 100% of the D&O premiums?

A. No. PGE is requesting 100% of the first layer of D&O coverage and 50% of supplemental layers. PGE made these adjustments to mitigate customer costs for insurance. Although we have made these reductions in this filing, we still believe that the inclusion of 100% of D&O insurance premiums in customer prices is appropriate.

Q. Why does PGE purchase Workers' Compensation insurance?

A. The State of Oregon requires PGE to maintain coverage to provide employees who are injured on the job with insurance coverage that will compensate them for lost wages, medical care, and if necessary, vocational rehabilitation.

2. Retained Losses

Q. Please explain Retained Losses.

A. Retained losses are the portion of any claim falling within PGE's self-insurance retentions for its Auto Liability, General Liability, and Workers' Compensation exposures that are frequent and predictable. Simply put, retained losses are the amounts borne by PGE before any insurance recoveries.

Q. What is the forecasted increase in annual claim expenditures for retained losses in Workers' Compensation and Auto and General Liability?

A. As shown in Table 5 above, PGE expects annual cash expenditures for retained losses for Workers' Compensation and Auto and General Liability claims to increase by an annual average of 14.1% from 2016 to 2018. The actuarial projection of annual expenditures for Workers' Compensation and Auto and General Liability retained losses is directly correlated to PGE's actual loss experience over time. In 2017 and 2018, PGE's annual expenditures are budgeted at the expected level, based on the actuarial projections.

IV. Environmental and Licensing Services

Q. Please describe the change in environmental and licensing costs from 2016 to 2018.

A. Environmental and Licensing Services (ELS) forecasted costs, as charged to A&G, are approximately $2.2 million for 2018 compared to approximately $4.4 million in actuals for 2016.

Q. Why did ELS costs decline?

A. This decrease is primarily due to the removal of environmental remediation costs and revenues associated with the Portland Harbor Superfund Sites (Portland Harbor), the Natural Resource Damage obligation (NRD),[10] the Downtown Reach portions of the Willamette River, and the Harborton Restoration Project (Harborton) from base rates. If excluding these costs from both 2016 actuals and the 2018 forecast, ELS costs charged to A&G still decrease by approximately $0.8 million.

Q. Why has PGE removed these costs from base rates?

A. PGE has removed these costs to reflect a stipulated agreement between PGE, Staff of the Public Utility Commission of Oregon, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities, stating that PGE will defer and record all environmental costs and offsetting revenues associated with Portland Harbor, NRD, Downtown Reach, and Harborton in the Portland Harbor Environmental Remediation Balancing Account (PHERA) as described in Docket No. UE 311, PGE Exhibit 100.[11] This agreement, however, is still awaiting a decision from the Commission. If the Commission's decision is materially different from the above referenced stipulation, PGE will seek to include the 2018

[10] The amounts of NRD damages or mitigation to natural resources are measured in Discount Service Acre Years.
[11] Associated Docket Nos. UM 1789, UP 344, and UE 311 have since been consolidated into Docket No. UM 1789.

forecasted costs associated with Portland Harbor, NRD, Downtown Reach, and Harborton into our 2018 test year forecast.

V. Summary

Q. Please summarize your request for A&G in this filing.

A. We request that the Commission approve PGE's forecast of $172.1 million in A&G costs in the 2018 test year. This represents a $1.2 million increase from 2016 actuals due primarily to increases in employee benefits (i.e., health care and dental premiums), safety, security and emergency management, and support services.

Absent cost increases for employee benefits and IT (plus the increase associated with OPUC fees), PGE has reduced its 2018 A&G forecast with an overall annualized 4.1% cost decrease from 2016.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
601	Summary of A&G Costs and FTEs
602	Description of Insurance Coverage
603C	Summary of Insurance Policies/Premiums
604	2018 R&D Proposed Projects

PGE Exhibit 503
PGE 2019 R&D Proposed Projects
Brief Descriptions

The below R&D projects will be brought before PGE's Research and Development Committee for consideration and prioritization in 2019. PGE expects most of these projects will be continued through 2021. Due to the fluid nature of research projects, funding amounts are subject to change.*

These projects primarily relate to the below topics of application:

SG	Smart Grid
SR	System Reliability
RP	Renewable Power
OE	Operational Efficiency
ES	Energy Storage
SY	System Resiliency
S	Safety

* While a large majority of the projects listed are expected to be completed on-time and on-budget, some projects will be delayed and/or require budget modifications due to unforeseen circumstances. It is common for dollars budgeted for projects that face delays to be reallocated to research priorities and opportunities that emerge during the year.

Brief Description	Topic
1. **<u>EPRI P1</u>** <u>- Power Quality (3-year)</u> This program encompasses three separate modules. PS1A which is improving power quality (PQ) in the transmission and distribution system, PS1B which is integrating PQ monitoring and intelligent applications to maximize system performance, and PS1C which is achieving cost-effective PQ compatibility between the electrical system and future loads. These three modules will help PGE (Portland General Electric) with the increased grid complexity by testing new grid components such as smart inverter, smart meters, photovoltaic (PV), etc. This will also help PGE move PQ from merely reacting to understanding, managing, and preventing tomorrow's PQ issues. The goal would be to maximize the value from PQ data streams to better deploy advanced, low cost PQ techniques to improve the grid reliability. The entirety of the P1 program is to solve real, valuable utility issues through PQ expertise and research. Some examples include advanced diagnostics using PQ data to help anticipate equipment failure, advanced data visualization and validation, and PQ assessments of distributed energy resources (DER) technology. <u>Customer Benefit</u>: The customer would benefit from increased grid reliability by utilizing smarter systems and making optimal use of existing PQ data streams to anticipate equipment failure, predict future PQ reliability issues, and build a smarter grid. By assessing the impacts of DER, PGE can better plan for the future and avoid potential PQ impacts to the customer.	SR
2. **<u>EPRI P60</u>** <u>- EMF and RF Health Assessment & Safety</u> The Electric Power Research Institute's (EPRI) Program 60 addresses electric and magnetic field (EMF) and radio-frequency (RF) exposures and health issues. Planning and building new transmission and distribution (T&D) projects takes on heightened importance as the power grid is upgraded and modernized by increased asset capacity and integration of smart grid technology and remotely-located renewable energy resources. New T&D construction and capacity upgrades to T&D lines and substations, building electric vehicle (EV) charging infrastructure, and expansion of smart grid technology's reliance on two-way wireless communication, can create public concerns about possible human health risks from EMF and RF exposures. Such concerns can lead to lengthy delays and regulatory decisions affecting project schedules and costs. Program 60 provides PGE with research, analyses, and expertise to better inform public dialogue and regulatory oversight. It is comprised of two project sets, P60A: Community and Residential Studies and P60B: Occupational Studies. These deliver timely, reliable EMF and RF research results, including communication materials, relevant background information, and analyses of key external studies. Program 60 research, combined with EPRI staff expertise, contributes to EMF and RF scientific knowledge, better enabling objective health risk evaluations and exposure guideline development aimed at reducing uncertainties for PGE customers and PGE workers . <u>Customer Benefit</u>: Both EMF and RF have been classified by the International Agency for Research on Cancer as possible human carcinogens. As our infrastructure ages, the grid expands to address electric vehicles, renewable integration, and new technologies (T&D construction, smart meters); we need to understand the latest in EMF research. PGE's support of P60 demonstrates our leadership and proactive approach to addressing potential community and regulatory concerns. Without this participation, PGE would be unable to access experts and the benefits of EMF and RF research geared toward the electric utility industry. Ultimately, the EPRI EMF/RF Program provides research, analyses, and expertise to better inform public dialogue and regulatory oversight on EMF and RF health and safety issues that is based on sound science.	S
3. **<u>EPRI Program 62</u>** <u>– Occupational Health and Safety (3-year)</u> The Electric Power Research Institute's (EPRI) Program 62 (P62) provides members with research relevant to current and anticipated occupational health and safety (OH&S) issues. The deliverables derived from PGE's engagement will be used to build, update, and sustain our occupational health and safety program. P62 also provides the ability to guide future Oregon Health& Science University ("OHSU") research for the industry while leveraging the experience, ideas, and funding of other electric utility companies. Deliverables relate directly to the influence of worker protective clothing (heat/cold stress); economic evaluation of ergonomic interventions; economic safety metrics/indicators; development of an exposure database; and SF6 decomposition by-products. Additional deliverables include monthly safety webcasts (recorded), a technical workshop, and access to EPRI's technical staff. By utilizing EPRI, PGE has an information resource that will allow for better short- and long-term safety planning and strategizing. The program is designed to address both current issues and anticipate those of tomorrow.	S

Brief Description	Topic
Customer Benefit: Participation in Program 62 will provide access to past, current and future research designed to address safety and health issues facing PGE. Implementing these research findings will lead to enhanced customer service and operational efficiency through the development of improved safety practices and procedures.	
4. **EPRI P88 -** Combined Cycle HRSG and Balance of Plant (3-year) This research will use work performed by EPRI to improve the design and operation of the heat recovery steam generators (HRSGs) at PGE. This work can be utilized by plant operation and maintenance teams and the corporate engineering group for the design of new plants, and the project engineering group when it comes to new upgrades/improvement projects to ensure that the new projects take into account the latest and best practices are included in the new design. The research information included in Program 88 will provide training material for PGE employees, and keep best practices available so that PGE works proactively in identifying issues and addressing them before these issues can become safety concern or impact plant reliability. Joining Program 88 will also allow PGE to have input on the projects that will be evaluated by EPRI and participating industries that are not electric utilities. This will benefit PGE by having EPRI work on projects that are specific to PGE. PGE can also benefit by utilizing the EPRI team as a resource when it comes to evaluating design of new projects or other evaluations related to program 88. PGE currently owns 3 HRSGs not including Beaver or Coyote 2 unit. Some of the plants are around 10 years old and it will be very important for PGE to stay at the forefront of the new research and apply the latest technology to our HRSGs. This may be even more important as PGE prepares to enter the Energy Imbalance Market (EIM). Customer Benefit: To meet customer requirements and keep electricity affordable, PGE needs to be smart in how it operates its assets. Research developed from Program 88 will allow PGE to be proactive in finding and mitigating potential issues before those issues result in forced outages and costly repairs. Participation in Program 88 will also support the development of a Covered Piping Program (a code requirement for Carty) to inspect insulated high energy piping systems at set frequencies for high stress and high risk (i.e. near walkways, control room, etc.) areas. PGE plant personnel work around these dangerous systems every day, safety is of utmost concern and proactive inspections can help ensure pipe integrity is maintained.	SR
5. **EPRI P161 -** Information and Communications Technology Diverse areas of research covering Emerging Technologies and Technology Transfer, Information & Communication Technology (ICT) for Transmission, ICT for Distribution, ICT for Distributed Energy Resources (DER), Enterprise Architecture & Systems Integration, Advanced Metering Systems, and Telecommunications. EPRI's goal is to "conduct research/development/demonstrations to promote the reliability, flexibility, resiliency and security of data transport and management to support grid operations." Applicable research areas include ICT/Security Architecture for Distributed Energy Resources, data management, GIS best practices, centralized vs decentralized control, augmented reality, business efficiency, telecommunications management, and persistent Wi-Fi. Customer Benefit: Improved effectiveness of customer programs requiring integration, including Distributed Energy Resources, Demand Response, and Smart Cities. Improved reliability (fewer customer outages) through implementation of smart grid applications and more efficient use of existing AMI & GIS investments.	SG
6. **EPRI P174 -** Integration of Distributed Energy Resources Increased amounts of distributed energy resources (DER) in the electric grid bring a number of challenges for the electric industry. Utilities face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options are involved. Furthermore, providing reliable service as DER penetrations increase and electricity sales diminish can also add economic and business challenges to the technical ones. This Program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, and integration analytics. The Program evaluates case study experiences and strategies related to future business impacts. It also evaluates leading industry practices for effective interconnection and integration with distribution operations. Many of these activities support EPRI's "The Integrated Grid" initiative. This Program includes lab and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is	SG

Brief Description	Topic
to expand utility hands-on knowledge for managing distributed energy resources—without reducing distribution safety, reliability, or asset utilization effectiveness. <u>Customer Benefit</u>: The optimal integration of distributed energy resources, like solar photovoltaic (PV) generation, has the potential for significant public benefits. These include reduced climate impact of overall electric power generation, potential for more efficient and optimum operation of the electric system through efficient generation closer to the load and even improved resiliency with local generation to provide power during major events on the grid. Achievement requires making these distributed resources a part of the planning and operation process inherent to an Integrated Grid.	
7. <u>**EPRI Program 180** – Distribution Systems</u> Distribution system owners need to continually improve the efficiency and reliability of the distribution system, to accommodate a higher penetration of distributed energy resources (DER), and to maximize utilization of existing distribution assets without compromising safety and established operating constraints. Significant changes to distribution design and operating practices are needed to accommodate these new requirements. At the same time, utilities will continue to grapple with the ongoing challenges of an aging infrastructure, increasing customer expectations, increasing competition for resources, and an aging workforce. Recent experience with major storm events has also revealed a need to re-examine practices for designing, maintaining, and operating the distribution system to improve its overall resiliency. EPRI's Distribution Systems Program has been structured to provide members with research and application knowledge to support planning and management of the grid today and the transition to a modern integrated grid. The Program delivers a portfolio of tools and technologies to increase overall distribution reliability and resiliency; understand the expected performance for specific components throughout its life cycle; assess methods for evaluating the condition of system components; and develop and test new technologies. The program delivers a blend of short-term tools such reference guides and industry practices as well as longer-term research such as component-aging characteristics and the development of new inspection technologies. Overall, the Program includes research that supports grid modernization and provides tools for planning, design, construction, maintenance, operation, and analysis of the distribution system. <u>Customer Benefit:</u> The research areas provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently, reducing customer outages as well as costs.	OE
8. <u>**EPRI P183** - Cyber Security</u> This program develops an analysis framework to correlate cyber, physical, and power system events including: • Development of security event scenarios that utilities can adapt to their operational environment • Identification of operational and asset condition data sources to support event detection; and • Results and lessons learned from testing and demonstrating scenario detection in EPRI's lab as well as utility host sites. Utility enterprises are evaluating cyber security threats to their communication networks in a way that integrates that information with other traditional information about equipment health status and power system status. It is now time to integrate this information into a comprehensive and consistent picture, for use by power system operators and communication system operators, in order to provide a system-wide view and to improve coordination of operator responses. This project intends to focus the "Analysis" component of the Integrated Threat Analysis Framework (ITAF) by developing and testing broadly applied use cases and potential data analysis methods to determine when a malicious event has taken place. While the aggregation of data from these domains (Information Technology, Operations Technology, Physical, threat indictors, etc.) provides a view across the entire utility enterprise, determining how to use this information to make decisions will be very challenging. The operational environment will vary day-to-day due to changing conditions (weather, loading conditions, availability of variable resources, planned or unplanned maintenance, etc.) so the use cases must be dynamic and represent a growing knowledge base as opposed to a set of static scenarios. This challenge will require expertise in both cyber security and grid operations. This project coordinates activities of three EPRI research programs: Substations (P37), Grid Operations (P39), and Cyber Security (P183) in a way that is intended to provide broad power industry and public benefits, including better communication between diverse utility personnel and public service personnel. <u>Customer Benefit</u>: This project will provide research in the support of providing safe, reliable power by	SR

Brief Description	**Topic**
identifying digital threats to and remediating vulnerabilities to PGE technology infrastructure. Customers will benefit from increased safety and reliability of the electrical grid.	
9. **EPRI P199 -** Electrification for Customer Productivity PGE's industrial and commercial customers are constantly striving to increase productivity and enhance their competitiveness in the global marketplace. In many cases, electrification – i.e., the application of novel, energy-efficient electric technologies as alternatives to fossil-fueled or non-energized processes – can boost utility productivity and enhance the quality of service to these customers. Electricity offers inherent advantages of controllability, precision, versatility, efficiency, and environmental benefits compared to fossil-fueled alternatives in many applications. A lack of familiarity and experience with emerging technologies, however, impedes many customers, particularly small- to medium-sized businesses and civil institutions, from pursuing electrification measures that can improve the productivity and efficiency of operations. Such enterprises would benefit from information and support from PGE. However, electric utilities themselves face obstacles to serving as effective utility partners in this regard. Identifying and measuring the prime opportunities for electrification in a given service territory can be difficult. One of these is the lack of an analytical framework for quantifying the net benefits of electrification strategies – from the customer, utility and societal perspectives. The P199 research program aims to address gaps like this by developing and refining analytical tools and an objective knowledge base of technologies, applications, and markets and facilitating stakeholder networks to help utilities evaluate and pursue electrification opportunities in partnership with their customers. Customer Benefit: This program enables customers to enhance productivity and product quality, save money and improve competitiveness through electrification. In some instances efficiency improvements will also result in positive environmental impacts.	SG
10. **EPRI P200** - Distribution and Utilization The distribution system is changing at an ever increasing pace, much more so than any other area in the power system. Much of this has been driven by changes in customer behaviors (e.g. customer adoption of distributed energy resources, net metering etc.). Tools and methods for planning and operating the distribution system were not designed to meet this changing landscape. Distribution systems have been designed for one purpose: reliably serve all customers in a safe and cost effective manner. However in this new era additional objectives must be considered as well, including accommodating high levels of DER, increasing resiliency, improving operational efficiency, and actively using distribution systems to provide bulk system services. Traditional planning methods utilizing rules-of-thumb are no longer sufficient and methods and tools for truly optimizing distribution planning and operational functions are necessary. Tools and technologies, such as distribution management systems, automation systems, protection systems, and planning tools must adapt to facilitate the needs of this new distribution system. New technologies and their integration will be critical to allow distribution planners and operators to meet these goals and realize this concept of an "Integrated Grid." P200 has been structured to provide research and application knowledge to support planning and management of today's grid as well as tomorrow's. The Program includes research that supports grid modernization and provides tools for planners, operators, and analysis experts of the modern distribution system. This program will serve as the hub for all activities related to distribution planning and operations. Customer Benefit: The research areas provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently, reducing customer outages as well as costs.	SG
11. EPRI P87-Fossil Materials and Repairs Program 87's objective is to provide integrated material selection guidance, corrosion mitigation methods, and repair techniques to improve safety, performance, and reliability - especially as related to Creep Strength Enhanced Ferritic Steels (CSEFS). EPRI research on Post Weld Heat Treatment (PWHT) exemption methods related to grade P91 and other CSEFS can decrease plant outage times as well as reduce operations and maintenance-related costs; this is important as PGE now has many facilities constructed using CSEFS. Similar to many other utilities, PGE is concerned about the impact of their aging workforce. Program 87 research provides a large body of knowledge to draw and benefit from as plant and associated support staff near retirement. Technology transfer deliverables include materials and repair guidelines, handbooks, technical projects, webcasts, position papers, and conferences/workshops. The program helps manage and	SR

Brief Description	Topic
reduce the operating risks associated with material degradation and failure. PGE will be hiring a new welding specialist later this year as part of their succession plan, further increasing the value of participating in this program now. Some of the resources of immediate need that are covered by Program 87 are included below. • Post Weld Heat Treatment (PWHT) exemption methods related to grade P91 and other CSEFS materials. The high energy small bore piping constructed at Carty used a significant amount of grade P91 piping materials that require post weld heat treatment (PWHT) for any repair. Innovative methods derived from the EPRI program can be used to obtain exemption from this requirement for any field repairs. PWHT is extremely costly and time consuming during repair cycles. • New weld methods and procedures associated with dissimilar metal welds (grade P91 to P22 and P22 to stainless steel). Dissimilar metal welds are the most common locations for weld failures in the industry due to the stringent material joining requirements applied to these materials. Customer Benefit: Access and utilization of the research from Program 87 will ensure that all specifications, repairs, acceptance criteria, life management programs, maintenance practices and new project designs incorporate current best practices to maintain asset reliability and operational efficiency. Customers will benefit from the collective experience of the industry in the procurement, acceptance, installation, repair, management and maintenance of the materials found throughout its generating plants, helping reduce forced outages and costs.	
12. **EPRI P198** Strategic Sustainability Science Power companies face unique challenges and tradeoffs managing financial, environmental, and social performance while providing safe, clean, reliable, and affordable electricity. Leveraging EPRI's decade-long stream of sustainability collaboration and research, the resources and tools developed through this new Strategic Sustainability Science Program will provide electric power companies the opportunity to take sustainability to the next level, embedding it into day-to-day operations and long-range strategic planning; exploring where the most efficient and effective sustainability change is made across the industry's value chain; engaging with cross-sector thought leaders to explore what "sustainable electricity" means and how to enhance effective communications; and using systems thinking to define how the electric power industry fits in a sustainable economy. The Strategic Sustainability Science program brings together sustainability leaders to steer progressive work, driving innovative projects that are not currently being done anywhere else in collaboration with member companies and industry stakeholders. Resources and tools emerging from this research can help electric power companies increase overall value, operate efficiently, better-mitigate risk, meet growing customer expectations, and enhance engagement with employees and industry stakeholders. The program serves as the future of sustainability–related research for the electric utility industry. Customer Benefit: As noted, PGE's customers have expectations around the sustainability of our business and many of them have sustainability commitments of their own. Participation in this program demonstrates our commitment to sustainability as we seek to build business value while simultaneously acting as environmental stewards and corporate citizens in the communities we serve. This program will provide the tools to better embed a sustainability mindset at our company, and better communicate to our customers not only how we're working to be more sustainable, but actually engage them in the conversation as we seek to collaboratively and proactively meet their expectations and needs.	OE
13. **PSU – Battery Backup Field Demo**; Residential and Grid As electric utilities experience increasing penetration of distributed renewable power generation (wind and solar) resources at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. Energy storage devices will be needed to store energy when it is abundant and to release it when needed. Development of the energy storage devices will enable the grid to respond with demand side controls and limit peak power demand. If available in sufficient capacity, energy storage devices will help resolve the present "non-dispatchability" of wind and solar power assets which currently dominate the renewable power generation resource stack mix.	ES

Brief Description	Topic
This development will advance the incorporation of more of these types of renewable power in response to carbon emission reduction policies through the promotion of renewable energy standards (RPS). To accomplish this on a more distributed basis requires that PGE take steps similar those described above for incorporation of renewable power sources such as wind and solar. This can also be done using energy storage alone on a distributed basis. PGE has collaborated with Portland State University's Electrical and Computer Engineering (ECE) Department to take steps in the placement of battery energy storage devices at residential locations. This collaboration will allow the testing and use of a very safe aqueous ion battery that has more energy density than power density, and more suitable for household use. The vision is that PGE would own and maintain the 7 to 8 KW inverter and the nominal 50 kWhr battery as investment assets so that: • PGE, through an agreement with the premise owner, can use the battery • Controls for the battery would enable demand response, wind firming, etc. • Upon loss of utility power a disconnect allows the battery to power the home • Upon re-gaining utility power the inverter will allow automatic grid re-synching • The inverter will also monitor and control for islanding conditions • The meter for the system will track energy for home and grid separately • The meter also supports circuitry to facilitate telemetry, command and control PGE expects the battery will serve PGE's purposes for the vast majority of the time. For the home owner, the battery-inverter will provide the peace of mind of having back-up power for that short period of time that loss of power is experienced on PGE's grid. Customer Benefit: The battery will be supporting the increased penetration of customer-hosted renewable generation (e.g. solar) on PGE's grid.	
14. **Data Analytics and Visualization POC** This Proof of Concept (POC) will engage three vendors (mPrest, OpusOne and innowatts) that will demonstrate their ability to provide high value to PGE's Integrated Grid initiative. The POC will focus on specific use cases, including improved load forecasting capability, identification of under- and over-loaded transformers and the ability to wrap multiple systems into a system-of-systems. Customer Benefit: This POC will provide multiple planning and operational value streams to PGE and its customers. These include: (1) The ability to rapidly integrate multiple systems provides high value by reducing O&M costs and operational miscues that result in poor data used to make capital and O&M decisions. (2) Improved load forecasting would result in the ability for PGE to better manage its operational business during both peak and non-peak events. (3) Improved load forecasting may provide PGE the ability to inject additional energy into the EIM or other markets that may emerge over the next several years. (4) The capability of identifying overloaded and under loaded transformers will reduce the risk of an outage, thereby improving outage metrics and improving the customer experience of PGE's customers. (5) Implementing a data bus approach will reduce human error, lag time between manual updates of multiple systems, facilitate data governance, data analytics and provide a higher-level of confidence in data quality and decision making thereby enhancing decision quality and speed of decision making in multiple areas. (6) Begin to move the needle on PGE's data analytics and visualization in a manner that directly supports the Integrated Grid Strategy. (7) The speed of integration, if realized, will accelerate PGE's development and delivery of an energy exchange platform necessary to support SB978 and corporate goals.	OE
15. **PGE Employee EV Research Program Extension and Data Analysis** With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up – for example:	SG

Brief Description	Topic
• charging and driving habits of EV customers • battery life & degradation as it relates to a driver's charging & driving habits • impact of TOU rate schedule on EV charging • commuting habits of EV drivers PGE has pursued this research via studying the driving habits and usage of PGE employees as part of this R&D project. Customer Benefit: Gathering data on electric vehicle driving and charging habits will enhance customer service by ensuring that future transportation electrification programs are designed to meet the needs of electric vehicles with longer driving ranges. Currently, only 2 of our 124 program participants currently own vehicles with ranges in excess of 200 miles due in part to the delays in release of the Tesla 3).	
16. **Use Of Imaging & Artificial Intelligence** To Enhance Vegetation Management Investigate the use of Lidar and Hyperspectral Imaging in addition to Artificial Intelligence computing to enhance operational efficiencies in vegetation management, utility asset management, system planning, and other operations. This program concept could be scaled up or down. Initial estimate to get a reasonable sampling size on our system is $500,000. Customer Benefit: This research area will allow us to operate and maintain the T&D grid reliably and efficiently, reducing customer outages and lowering O&M costs.	SG
17. **OSU – Microgrid Synchrophasor** The goal of this project is to better understand load models in order to advance grid protection of the next generation (integrated grid) power transmission and distribution infrastructure. With assistance from the growing PMU network at Oregon State University (OSU), a composite dynamic load model can be estimated in real time and provide useful insight into the design of microgrid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping. This project will provide PGE and its customers with insights about the benefits of deploying phasor measurement units (PMUs) at the distribution level yielding improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing. Customer Benefit: OSU is investigating advanced monitoring and protection techniques for application in an evolving integrated grid. Investing in synchrophasor research at OSU will produce benefits from smart grid knowledge and employee pipeline development. Lessons from this research will aid PGE's business model transition from a mono-directional hierarchical power delivery model to that of customer-centric dynamic power balance services, through developing enhanced operational strategies at the distribution system level. This transition will ultimately support reliability, operational efficiency, energy use optimization, peak shaping, resiliency, and distributed renewable resource integration.	SG
18. **OIT – Second Life Battery Research** This project allows PGE in collaboration with Oregon Institute of Technology (OIT), to learn about and implement uses of second life batteries. In particular, there is a desire to better understand the comparative life cycles of Li-Ion, Zinc-Bromide, and Sodium-Sulfur batteries as it applies to grid level storage/islanding applications. The approach would be to obtain multiple types of batteries that are candidates for the second life study: (1) Perform SOC (%), (2) capacity, (3) life cycle, and efficiency, (4) charging-discharging, and reaction time analysis of candidate electro chemistries. This project will deliver a formal, evaluated report with the comparison data. These results would allow PGE to be better positioned to understand how 2nd life uses of long-lived batteries can be cost-effectively applied to other applications that will benefit its customers. These tests will be conducted at Oregon Renewable Energy Center (OREC) under a controlled environment. Customer Benefit: PGE customers will potentially benefit from expanded deployment of cost-effective battery storage, supporting the increased penetration of renewable generation (e.g. customer-owned solar) on PGE's grid.	ES
19. **BPA R&D Project (T&D Node/Breaker Modeling)** Economic drivers push the power system to operate with leaner margins. Compounded by higher uncertainties introduced by the emerging mix of renewable generation and smart loads, meeting reliability standards and minimizing blackouts and outages are increasingly a bigger challenge. Tackling this	SG

Brief Description	Topic
challenge requires accurate network node/breaker models. Presently, the calculated path flow based on network models differs from real time values ranging from 100 MW to 900 MW, which is 5% to 25% of the actual flow. Currently there is no single data source where utilities can get an accurate and validated WECC-wide model at any time. The model difference causes reliability issues, inaccurate pricing (LMP) values, and loop flows. Subsequently this negatively impacts congestion mitigation plans. With this in mind, the goals of this proposed project are: - Identify the barriers to a common WECC-wide node/breaker model - Identify techniques and approaches to address the barriers - Develop the requirements to obtain a regional model for BPA, PGE, other ISOs, reliability operators, Peak, and WECC - Reduce external model maintenance efforts for all parties while improving the quality of the model. This proposed work will deliver a report documenting the techniques and requirements, with examples to demonstrate feasibilities. The report will guide the actual development of a set of automation tools that build, validate, maintain, and host the common WECC-wide node/breaker model. Such development is beyond the current proposed work and is intended to be subsequent Phase 2 work. An accurate model is essential for BPA, PGE and other utilities to assess the impact of Energy Imbalance Market (EIM), reliability, congestion mitigation management; Stability Operating Limits (SOL) calculations, Available Transfer Capability (ATC) calculations, as well as accurate forecasts for transmission upgrade projects. <u>Customer Benefit</u>: This research will provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently, reducing customer outages and costs.	
20. **<u>NEEA End Use Load Research</u>** This project involves participating in the End Use Load Research (EULR) Project being managed by NEEA. The purpose of the EULR project is to obtain a representative sample of electric end use load shapes, as this data has not been collected since the 1980s. This data will be collected continuously over a five year period and will be accessible through an online database to participating parties. <u>Customer Benefit</u>: Detailed end use data has a number of important uses for PGE, including informing our deep decarbonization planning, demand response planning, bottom-up forecasting, and rate design. Accurate load profiles for customer end-uses aid in demand response opportunities, forecasting changes in energy usage based on the penetration of technologies, and understanding how to balance customer end-use to enable greater penetration of renewables.	OE
21. **<u>Distributed Storage for Community Resiliency</u>** -<u>PREBHub</u> PGE will support deployment of and research of three community resiliency "PREPHubs". PREBHub is a concept pioneered by MIT's Urban Risk Lab to support disaster resilience. Composed of flexible kit of parts, each element serves the community in both every day and emergency scenarios (e.g. solar/battery, radio communications, public Wi-Fi, cached goods, lights, etc.). The City of Portland has expressed interest in demonstrating the PREPHub concept in Portland to create a visible/tangible face for the City's BEECN network. A BEECN is a temporary radio communications site to go in Portland after a major earthquake to ask for emergency assistance if phone service is down, or report severe damage or injury. There are 48 locations throughout Portland. The PREPHub team is proposing to install three PREPHubs in 2018 across Portland. Each site will include a residential energy storage device (e.g. Tesla PowerWall or Sunverge SIS). During regular operations, the devices will be managed by PGE and PSU as an extension of PGE's existing residential storage demonstration project. During an outage the device will island from the grid and provide backup power to the PREPHub which will power small plug loads (e.g. emergency communications, charging of cell phones, etc.). Further, the units will have small solar arrays to extend power availability for a limited duration in the event of an outage. PSU will use the sites to expand upon existing research on controlling and aggregating distributed energy storage for PGE. <u>Customer Benefit</u>: The project supports benefits for customers in several ways: 1. Directly supports municipal customers seeking community resiliency solutions. During a major	ES

Brief Description	Topic
event, the batteries will support customer plug loads (e.g. cell phones) which has been identified as a priority by the City of Portland. 2. Though small, the storage devices in the PREPHubs will be used for grid services day-to-day (this includes capacity, energy & ancillary services, etc.) 3. Customers will benefit from the learnings associated with this project. Advancing our learning of aggregation, control, and dispatch of distributed storage has the potential to reduce integration costs for future Distributed Energy Resource (DER) programs.	
22. **Cascadia Lifelines Project** The Cascadia Lifelines Program is a targeted research consortium aimed at improving Oregon's infrastructure resilience in a cost and value informed manner. Professor Dan Cox is the director of the program. Regular members at a cost of $50,000/year are ODOT, PGE, NWN, BPA, and PDX. Being at this level provides you a seat on the Joint Management Committee. It is important because the Joint Management Committee determines the research projects and this is a continuation of PGE's support over the last five years. Customer Benefit: By co-funding Cascadia Lifelines R&D projects, PGE's customers benefit from a more resilient grid during emergency events.	SY
23. **Smart Streetlights - Phase 3** In 2018 PGE engaged Portland State University in a research project to investigate and demonstrate 'smart' streetlights. A market assessment of technologies conducted by PSU supported pursuit of a demonstration pilot project with Sensus, PGE's AMI vendor and Telensa, the world-wide leader in smart streetlight deployments. A two phase demonstration project was initiated. Phase 2 will demonstrate the system's ability to remotely brighten, dim and flash the lights, and to support secure user roles (e.g. shared control) for PGE and municipalities. Completion of this research is critically important. Customer Benefit: Smart streetlights will use less energy. Outages will be detected near real-time, improving the PGE's responsiveness to maintenance needs (and improving safety). Municipalities will be able to program streetlights to address specific needs and use cases (e.g. emergencies and traffic conditions). Billing will be done on actual, as opposed to deemed, usage (an interest expressed by a number of municipalities).	SG
24. **Investigating Ductile Iron Poles for T-D Structures** Evaluate the use of ductile iron as a viable support structure material in PGE's system. PGE is soliciting the research capabilities of Oregon State University's College of Civil Engineering. This work will support a graduate research assistant for general investigations into the long-term performance of ductile iron poles. This will include a thorough literature review as well as accelerated testing of ductile iron pole sections conducted under three types of degradation scenarios. Those scenarios include: 1) Corrosive environment using OSU's Qfog system 2) Sulfate rich soil environment using either OSU's Qfog or MCMEC system1, and 3) Placement and initial measurements at OSU's long-term outdoor exposure site. During and after the accelerated aging, OSU will do electrochemical surface measurements (Eis) and scanning electron microscopy (SEM). Additionally, after accelerated aging, all specimens will be placed on OSU's outdoor long-term exposure site for continued monitoring. This will provide PGE with a repository of samples that can be measured periodically and will allow them continual updates, ahead of time, as to the long-term performance of ductile iron pipes. PGE has provided sections of ductile iron pipe and "comparison" pole material samples. Customer Benefit: Ductile iron poles have the potential to improve reliability and resiliency by eliminating woodpecker damage as one of the leading causes of premature wood pole failure. Additionally, the use of ductile iron poles addresses the growing concern around use of treated wood poles in environmentally sensitive areas.	SR
25. **PGE EV Infrastructure Smart Charging Pilot** The goal of this project is to evaluate the feasibility of using public electric vehicle charging infrastructure as a demand response resource. PGE owns and operates four 50 kW DC fast chargers and two 7.2 kW level 2 charging stations for public use on SW Salmon Street between 1st and 2nd Avenues. These stations are operated using the Greenlots software platform and, by upgrading the platform to include a demand response module, PGE would be able to call demand response events (reduce charging rates during critical peaks). This project would test multiple event deployment methods, including automatic curtailment,	SG

Brief Description	Topic
optional curtailment (ask users if it is OK to limit charging rates), and price signals (pay more to opt out). User feedback will also be requested. Customer Benefit: Evaluating public electric vehicle charging infrastructure for inclusion in future demand response programs benefits PGE's customers by exploring new resources for peak demand reduction. This project will also benefit customers by ensuring that future demand response programs are well designed, enhancing customer experience.	
26. **Salem Smart Power Center (SSPC) Voltage Control** In 2016, PGE completed a project at the Salem Smart Power Center (SSPC) to prove that the facility's 20 inverters could effectively and precisely control the voltage on Oxford Rural Feeder. This demonstration was successful, but it is not possible to keep the SSPC left in the voltage control mode because the inverter control system will interact negatively with the voltage regulators in the substation. The voltage control mode can operate autonomously if appropriate controls and communications are installed to interface with the voltage regulators in a safe and consistent manner. This project consists of installing controls at the substation to use the voltage regulators for course voltage control and allowing the inverters to perform fine control. Also, controls will be installed that revert voltage control to the voltage regulators when the system exceeds high or low voltage limits. Customer Benefit: This project would result in a feeder voltage with much lower variation than a typical PGE feeder. The Oregon State Data Center which is located on this feeder has expressed that there is a value in this to them for reliability. If the feeder voltage can be optimized to maintain the lowest voltage possible while not violating ANSI standards for voltage (+/-5% of nominal), customers will realize a modest savings in energy usage. This application will reduce the number of operations of the voltage regulators by a significant amount (possibly as much as 50%). This application will demonstrate the ability of smart inverters to enhance the integration of solar energy by diminishing the voltage fluctuations sometimes experienced with distributed solar PV systems. PNNL's report predicts an economic benefit of $393,000 to the net present value over the 20 year life of the project by implementing this control.	SG
27. **Ultra Capacitors** Industry wide, failure of starting batteries contributes to 70% of generator 'fail to start' problems. Compared to the traditional lead-acid starting batteries, ultra-capacitors offer 6 times the lifespan, 3 times the cranking amps and are less susceptible to temperature fluctuations. Ultra-capacitors are also more energy efficient as they use less energy to float charge and have faster recharge between cranking attempts. Dispatchable Standby Generators (DSG) regularly and prescriptively changes existing lead acid batteries for DSG generators. If the project is successful, we could start the changeover to ultra-capacitors from lead-acid technology. There would be a direct benefit to the DSG customers served by a successful ultra-capacitor test, and indirect benefits to all our other customers (by making DSG more cost effective and resilient). Future benefits to customers could include energy savings if the technology could replace less efficient battery systems for other applications. This project will be a good entry point into the ultra-capacitor market for PGE – as the technology improves, we believe the use of ultra-capacitors will increase dramatically. Customer Benefit: There would be a direct benefit to the DSG customers served by a successful ultra-capacitor test, and indirect benefits to all our other customers (by making DSG more cost effective and resilient). Future benefits to customers could include energy savings if the technology could replace less efficient battery systems for other applications. This project will be a good entry point into the ultra-capacitor market for PGE – as the technology improves, we believe the use of ultra-capacitors will increase dramatically.	SY
28.Wave Energy – OSU	RP

Brief Description	Topic
To advance Wave Energy and Modeling Research at Oregon State University (OSU). This project would provide support for the continued expansion of wave energy research & modeling, prototype linear test-bed testing, and resource evaluations being used to assess renewable energy potential in the Pacific Northwest. Customer Benefit: Advancing wave energy research will provide the benefit of encouraging new project development in Oregon. This would allow increased diversity in PGE's renewable resources portfolio, allowing more renewables to be cost-effectively delivered to customers.	
29. Solar PV Monitoring Lab - U of O The University of Oregon (U of O) collects data from a network of 30 Pacific NW monitoring stations. They submit this data to the National Renewable Energy Lab (NREL) and post this data on a Public website. The U of O maintains this network of solar PV monitoring stations. Customer Benefit: PGE's customers will benefit from access to enhanced, accurate information on regional solar resources, supporting continued adoption of PV in Oregon.	RP
30. BPA Collaboration - Coordinated Voltage Control The object of this research is to develop, simulate and validate a coordinated voltage control scheme for increasing Dynamic Transfer Capability (DTC) on California-Oregon Intertie and Pacific HVDC Intertie. This project will develop algorithms for coordinated voltage control and optimization of reactive power resources to increase DTC limits on the interties and internal flowgates. Customer Benefit: Optimizing the use of PGE transmission will reduce energy costs for PGE customers.	OE
31. **Fiber Optic Current Sensors** (FOCS): The FOCS technology has evolved into being of practical use for primary relaying current measurement in several distribution and transmission facilities. The benefits for this technology are: - Safety - Conventional Current Transformer shock and energy hazard related accidents will be eliminated - Fault current measurement inaccuracy caused by conventional current transformer saturation will be eliminated - Errors caused by analog to digital conversion to IEC 61850-9-2LE sampled values of conventional current transformers will be eliminated - Decreased handling and installation time when responding to conventional free standing CT replacements during severe outage events (e.g., seismic) The following will be performed on the two Fiber Optic Current Sensors benchmarked in the R&D exploratory project: - Test for compliance to IEEE 693-IEEE recommended Practices for Seismic Design of Substations - Confirm relaying current measurement accuracy - Confirm fault transient performance specifications - Determine if the effects of series and/or back to back shunt capacitor switching causes undesirable FOCS and Merging Unit operation - Measure and record real time data from staged fault testing of the installed FOCS Customer Benefit: The total estimated cost for this Project is $500k, PGE's share will amount to a fraction of this ($50,000 x 2 years) and provide full access to all of the learnings. These learnings should enable PGE to operate the grid more reliably and efficiently, reducing Customer outages and costs.	SG
32. Floating Solar PV Use a consultant to develop a project for installation of floating solar PV on PGE plant reservoirs. The integration of floating PV panels would allow shading and power generation. Shading of a reservoir helps to lower water temperature – better for fish habitat and decreased evaporative loses. The addition of solar PV at plant sites is ideal as interconnection, communications, metering, and O&M staff already exist. This type of installation could be used at the Carty Reservoir, PRB (i.e., Lake Billy Chinook, Lake Simtustus), and Faraday Lake.	RP

Brief Description	Topic
<u>Customer Benefit:</u> The floating solar PV would add more renewable power in PGE's resource mix.	
33. <u>Beaver Holding Ponds</u> Install, test and verify Carbon Dioxide gas injection as a means to control PH at Beaver Generation station holding ponds. Liquid sulfuric acid is currently used to control PH in the holding ponds. During the summer months a large quantity of acid is used which exposes Beaver Technicians to acid while totes are exchanged. Carbon dioxide may potentially be used as a substitute to create carbonic acid. This project will improve safety by reducing exposure to a highly corrosive acid. The substitution of bottled Carbon Dioxide gas can significantly reduce potential acid spills and allow for easy, modular refills. <u>Customer Benefit</u>: Carbon dioxide is approximately $0.14 per pound less than sulfuric acid. This project could result in significant savings if the project is determined to be applicable at other thermal facilities.	S
34. <u>Renewable Fuel Use for Dispatchable Standby Generation (DSG)</u> Test the environmental, maintenance, performance and cost impacts of using a renewable Diesel alternative fuel on emergency backup generators. The data and lessons learned will be an input to a recommendation to switch fuels. <u>Customer Benefit</u>: The Dispatchable Standby Generation group works with 86 customer owned emergency generators at 58 sites. We work closely with 38 different customers to provide a key service for critical backup emergency systems. The ability to offer a tested and approved diesel fuel alternative would deliver valuable environmental benefits to these customers, the customers that they serve and members of the community in which their generators operate.	RP
35. <u>PW2 Waste Heat Recovery Energy</u> The operation the PW2 reciprocating engines produce a large amount of waste heat form cooling the engine blocks. This waste heat could be used to produce additional energy via an Organic Rankine Cycle system. This project would hire a consultant to determine the amount of waste heat available from PW2 operation and the optimum organic motive fluid. This project would also determine the economic feasibility – with the goal of preparing a capital job for the CRG. <u>Customer Benefit</u>: PGE customers would benefit from an additional source of clean energy via waste heat recovery.	RP
36. Power to Gas – NWN This project will demonstrate, test, evaluate, and advance technical specifications for commercial production of hydrogen from electrolysis and methane production from woody biomass. This process will also provide ancillary grid balancing services to the grid. The proposed system will produce renewable natural gas (RNG) for PGE power plant fuel. The process uses the PyroCatalytic Hydrogenation (PCH) from G4 Insights – low temperature thermochemical production of RNG from lignocellulosic biomass. The electrolyzers will use excess renewable energy (e.g., during Spring runoff, peak solar, high regional wind) to produce hydrogen and can act as Dispatchable Load. <u>Customer Benefit</u>: PGE's customers will benefit from cleaner production of energy from PGE's gas fired plants and effective use of surplus renewable power during Spring run-off, off-peak wind generation and surplus solar that is expected to be exported from California.	RP
37. <u>PW2 Black Start Load Bank</u> Port Westward 2 is capable of providing Black Start for PGE's grid. Currently the plant can inject energy in to a load bank at the Trojan substation. As an alternative, a large chiller could be installed at Port Westward. During Black Start testing or during periods of low load – Plant energy could be used to operate the chiller. Then during peak loads – the energy can be recovered by mixing cold air from the chiller in to the Gas Turbine inlet to significantly improve unit Heat Rate. The Combined Cycle Combustion Turbine (CCCT) already has an injection grid on the turbine intake that the anti-icing system uses. Hire a consultant to evaluate the cost/benefit of integrating a chiller and if economic – prepare a Capital Job project for the CRG. <u>Customer Benefit</u>: PGE customers would benefit from the chiller acting as a Load Bank to allow reliability black start testing and benefit from a reduced cost of energy from PW1 due to improved Heat Rate.	OE

Brief Description	Topic
38. Fuel Gas from Landfills - Wastewater Treatment Plants Use a consultant / search engine to identify all landfills and wastewater treatment plants in the PGE Service Area. Contact owners/management at the identified sites to determine opportunities for recovery of flared methane gas to be used in firing onsite gensets. The energy produced can be used to supply the grid. Customer Benefit: PGE customers will benefit from additional renewable energy integrated to the grid.	RP
39. South Metro Area Regional Transit Electric Bus Project PGE will fund Portland State University's evaluation of customer-owned bus smart charging, including night-time wind following to support renewables integration. Results from the research will inform future charger deployments, potentially adding additional value streams and capturing additional environmental benefits associated with transportation electrification. Customer Benefit: PGE customers would derive benefit from the integration of more renewable resources and possibly avoided T&D expenditures if the chargers allow more efficient utilization of grid infrastructure.	SG

Exhibit 504
R&D Exhibit

Data Analytic and Visualization POC

This Proof of Concept (POC) will engage three vendors (mPrest, Opus One and innowatts) that will demonstrate their ability to provide high value to PGE's Integrated Grid initiative. The POC will focus on specific use cases, including improved load forecasting capability, identification of under- and over-loaded transformers and the ability to wrap multiple systems into a system-of-systems.

Customer Benefit: This POC will provide multiple planning and operational value streams to PGE and its customers. These include:

(1) The ability to rapidly integrate multiple systems provides high value by reducing O&M costs and operational miscues that result in poor data used to make capital and O&M decisions.

(2) Improved load forecasting would result in the ability for PGE to better manage its operational business during both peak and non-peak events.

(3) Improved load forecasting may provide PGE the ability to inject additional energy into the EIM or other markets that may emerge over the next several years.

(4) The capability of identifying overloaded and under loaded transformers will reduce the risk of an outage, thereby improving outage metrics and improving the customer experience of PGE's customers.

(5) Implementing a data bus approach will reduce human error, lag time between manual updates of multiple systems, facilitate data governance, data analytics and provide a higher-level of confidence in data quality and decision making thereby enhancing decision quality and speed of decision making in multiple areas.

(6) Begin to move the needle on PGE's data analytics and visualization in a manner that directly supports the Integrated Grid Strategy.

(7) The speed of integration, if realized, will accelerate PGE's development and delivery of an energy exchange platform necessary to support SB 978 and corporate goals.

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE's main All-Risk property insurance program is led by FM Global and insures PGE's property such as power plants, substations, office buildings, etc. from "all-risks" of direct physical loss or damage (including boiler and machinery), subject to policy exclusions, caused by perils such as fire, explosion, lightning, wind, ice, hail, flood, earthquake, and certain acts of terrorism. This policy specifically excludes coverage for PGE's transmission and distribution property as well as PGE's renewable projects. Under this program PGE maintains coverage limits of $1 billion with a $2.5 million deductible.
Renewable Property	The All-Risk property insurance program for PGE's renewable assets is currently placed in the London market. Operational All-Risk coverage for these assets, including both wind and solar, are insured to their combined full replacement value of $1.8 billion and carry a $0.15 million deductible
Director's and Officer's Insurance	Directors and Officers ("D&O") Liability Insurance shields PGE's directors and officers against the normal risks associated with managing the business. The insurance premiums requested in this case are reasonable expenses that are necessary to attract and maintain qualified and competent directors and officers and they provide a direct benefit to PGE's customers. Currently PGE purchases $140 million in D&O insurance limits with $.75 million deductible. No deductible applies to Side A, or individual coverage. The limits purchased are reasonable, necessary and consistent with the standard practice of the utility industry. The lack of an appropriate level of D&O insurance would make it difficult for PGE to hire qualified and competent people for positions at the director and officer level. In addition, lack of appropriate D&O limits would provide a significant motivation for our experienced directors and officers to seek employment elsewhere. Subjecting the Company to the potential of such adverse outcomes is not in the best interest of PGE's ratepayers.
General & Auto Liability	General and Auto Liability insurance covers PGE's legal liability from claims resulting from bodily injury or property damage arising out of PGE's operations, including the use of company vehicles. Given PGE's contact with its customer's premises and the dangerous nature of its operations, this insurance is of paramount importance. PGE maintains coverage limits of $160 million with a $2 million self-insured retention.
Nuclear	PGE is required by the United States Nuclear Regulatory Commission to maintain Nuclear Liability coverage for the on-site storage of its spent fuel until such time that the radioactive materials have been removed from the Trojan site. The coverage consists of three policies: (1) The Facility Form insuring PGE's legal responsibility for damages because of bodily injury, property damage, or covered environmental clean-up costs caused by the Nuclear Energy Hazard during the policy period and reported within ten years of the policy termination date. (2) Master Worker insuring PGE's legal obligation to pay as damages because of bodily injury sustained by a "worker" and caused by the nuclear energy hazard. "Worker" refers to a person who is or was engaged in nuclear related employment; (3) Suppliers and Transporters covering incidents caused by radioactive waste materials stored either temporarily or permanently at off-site locations not owned/operated by the insured.
Fiduciary	Fiduciary Liability insurance provides protection for officers and employees for both breach of fiduciary duties and other wrongful acts in the administration of employee benefits programs. This program is made up of total limits of $50 million with a $0.25 million self-insured retention.
Aviation (Helicopter)	This policy insures the helicopter's hull value from physical damage and provides $20 million of liability coverage in operating the aircrafts during PGE's aerial patrol operations.
Aviation (Unmanned Aircraft Systems)	This policy provides $5 million of liability coverage for operating Unmanned Aircraft Systems (also known as 'Drones') while conducting aerial patrols and inspections.
Cyber	The policy has several insuring agreements, providing coverage for: (1) damages and claims expenses due to theft, loss or unauthorized disclosure of personally identifiable non-public information or third party corporate information, (2) costs incurred to comply with a breach notification law, and (3) claims expenses and penalties in the form of a regulatory proceeding resulting from the violation of a privacy law such as HIPPA or FTC. PGE purchases a limit of $10 million with a $.25 million self-insured retention.
Fidelity & Crime	Insures losses incurred by PGE or its employee benefit plans as a result of the dishonest acts of employees, including embezzlement, forgery or the theft of money or securities. The policy has a $10 million limit and $0.5 million deductible. This coverage is typically excluded under most All-Risk Property policies and must therefore be purchased under separate cover.
Workers' Compensation	The State of Oregon requires PGE to maintain Workers' Compensation coverage to protect itself from catastrophic losses to employees arising out of and in the course of employment. This coverage sits above PGE's self-insured Workers' Compensation program.
Surety Bonds	In the course of doing business PGE must procure and maintain a number of Surety bonds throughout the year. These bonds allow PGE to do work for various state and city governments and agencies and are a requirement for maintaining a form of collateral for self-insuring PGE's Workers' Compensation obligations.

Exhibit 506C

Protected Information Subject to Protective Order 18-047

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Information Technology

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Larry Buttress

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Larry Buttress. I am the Interim Vice President and Chief Information Officer at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the 2019 test year forecast of PGE's Information Technology (IT) costs and explain the cost drivers for the increase from 2017 actuals. I also provide an overview of the activities, functions, and services provided by the IT operating area, as well as an update of the programs and initiatives for this functional area.

Q. Why do you compare your 2019 forecast to 2017 actuals?

A. As noted in PGE Exhibit 200, Section I, part B, this is because 2017 represents PGE's most recent full year of actual results.

Q. Please summarize the activities or functions that PGE categorizes as IT.

A. IT consists of the departments responsible for developing, operating, and maintaining our computer, cyber, information, and communication systems. These systems are becoming increasingly important to all aspects of PGE's operations (with increasing scope, reliance, and use) and this trend is expected to continue in 2019 and beyond. As PGE modernizes systems and processes, like all providers of critical infrastructure, we are becoming increasingly reliant on evolving technology. This increases our need for more resilient, secure, and reliable systems to conduct operations and provide customer service.

Likewise, cyber threats to these systems have increased significantly over the years, becoming more numerous and varied based on the source of the threat. More specifically, the level, severity, and frequency of the threats to utilities are increasing rapidly. In 2017, we blocked over 280 million events on our internet facing systems.[1] As a result, additional IT hardware, software, and staffing resources to maintain, monitor and protect our systems are required.

As PGE continues to improve the functionality of its systems and customer-focused products and services (in response to customer needs and expectations), our systems are experiencing incremental and continuous evolution. These systems are now more connected and integrated, requiring incremental resources to provide matching cyber capabilities with safer security platforms.

Q. By how much do you forecast IT Operations and Maintenance (O&M) costs[2] to increase?

A. From 2017 to 2019, we forecast incurred IT O&M costs to increase by approximately $24.8 million, from $56.7 million to $81.5 million as shown in Table 1 below. Because these costs relate to all areas of PGE's operations, they are directly charged or allocated to appropriate operating areas and appear as part of each area's O&M costs. Because the majority of these costs relate to corporate systems and are allocated to all operating areas rather than charged directly, we discuss IT as a whole in this testimony.

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[1] In mid-November 2017, PGE received advanced information from a threat intelligent resource, with which we have partnered, that could affect certain electric safety instrumented systems. This attack aligns with one of PGE's defined threat models associated with nation state actors. The threat actors have demonstrated ability to use a cyber attack to disrupt the safety instrument from functioning, resulting in a potentially life-threatening event.

[2] Unless specifically indicated as capital costs, all costs in this testimony refer to O&M costs.

Table 1
Total IT Costs ($ millions)

Category	2017 Actuals	2019 Forecast	2017-2019 Delta
Direct Charges to Operating Areas	$ 6.6	$10.6	$ 4.0
Allocated Charges to Operating Areas	50.1	72.6	22.5
Labor Adjustment		-1.7	-1.7
Subtotal IT Incurred	**56.7**	**81.5**	**24.8**
Labor Loadings	15.5	21.4	5.8
Subtotal IT Loaded	**72.2**	**102.8**	**30.6**
2014-2018 IT Deferred Mechanism	1.7	0.0	-1.7
Total IT*	**$73.9**	**$102.8**	**$28.9**

*May not sum due to rounding

Q. What are the major drivers of the forecasted O&M cost increase from 2017 to 2019?

A. The increase from 2017 to 2019 is primarily due to four factors: increases in hardware and software maintenance agreements, the Network Resiliency Project, continuing information security initiatives, and a movement in labor costs from capital to O&M. These drivers are more fully explained below.

Q. You mentioned allocated IT expenses; please elaborate about direct charging and allocating IT expenses.

A. As shown in Table 1 above, PGE's IT costs fall into three categories: directly charged (or assigned), allocated, and labor loadings. Directly charged costs relate to systems that are specific to a given operating area, such as transmission, distribution, or customer service. Consequently, these costs are charged directly to specific O&M accounts related to those operating areas. Other IT work in the areas of voice, data, network, communications, business recovery, the data center, and office systems, does not relate to any specific operating area; instead, these costs apply broadly to all PGE activities and departments. These costs are first charged to a balance sheet account (Account 1840004) and then allocated to certain expense accounts for the various operating areas. PGE Exhibit 601 provides a summary of the direct and allocated charges by operating area.

Q. What do the labor loadings represent?

A. The labor loadings represent payroll-related costs that consist of employee benefits, pension costs, incentives, payroll taxes, employee support, paid time off, and where applicable, injuries and damages. These costs are applied (loaded) based on specific rates per dollar of IT labor. Because the loadings are not specifically IT costs, but instead relate to total compensation, we discuss them in PGE Exhibit 400 rather than here. PGE Exhibit 200 provides detail on payroll taxes. Finally, PGE submits its loading and allocation policies annually to the Public Utility Commission of Oregon (Commission) Staff as an attachment to our Affiliated Interest Report.

Q. Why do labor loadings increase by $5.8 million?

A. Because labor loadings are calculated amounts, the increase in labor loadings is due to the increase in IT O&M labor on which they are based. The loadings effectively move costs from certain sections of the income statement to other sections. However, the net impact of this on PGE's revenue requirement is zero.

Q. Please explain the 2014 IT Deferral Mechanism.

A. This deferral mechanism began in 2014 and its amortization will end in 2018. As part of the UE 262 general rate case settlement process, parties stipulated that 2014 O&M costs associated with developing IT systems should be capitalized and subject to a five-year amortization. The stipulation, subsequently adopted by Commission Order No. 13-459, removed approximately $8.7 million of IT development O&M expense from PGE's 2014 revenue requirement and replaced it with a regulatory asset of approximately $7.8 million.

The annual amortization expense of approximately $1.7 million represents one-fifth of the initial capitalized total. As noted above, this mechanism ends in 2018 and is not included in PGE's 2019 test year forecast.

Q. How is the remainder of your testimony organized?

A. In the next section, I provide more detail on the drivers of the IT O&M cost increase. Following that, I discuss an emerging technology that will impact PGE's IT solutions going forward. I then provide a summary and conclusion of this testimony. In the final section, I provide my qualifications.

II. IT Operations and Maintenance Costs

Q. Please restate the amount of IT O&M costs in your 2019 test year forecast and the major drivers of the increase from 2017 actuals.

A. Table 1 shows that PGE's 2019 test year forecast reflects $81.5 million of incurred IT costs. This represents an increase of approximately $24.8 million over 2017 actual costs. The primary drivers of this increase are in hardware and software maintenance costs, the Network Resiliency Project, continuing cyber security initiatives, and a movement in labor costs from capital to O&M. I discuss each driver in more detail below.

A. Hardware and Software Maintenance Agreements

Q. By how much do costs for hardware and software maintenance agreements increase based on current and planned projects?

A. From 2017 to 2019, these costs will increase by approximately $7.0 million.

Q. Why are software and hardware maintenance agreements necessary?

A. These agreements are necessary to:

- Keep our software operational by having access to fixes and patches provided by the vendor.
- Enable us to obtain and retain appropriate licenses, since some vendors require the purchase of maintenance services as a condition of the software license.
- Receive regular upgrades to correct programming errors and provide continued technical maturity.

PGE must provide care and maintenance for our technology investments, which extends the useful life of our systems and provides the best value for customers.

Q. What are the primary reasons for the increase in hardware and software maintenance costs?

A. O&M costs for maintenance agreements on hardware and software tend to increase annually for the following reasons:

- Price escalation for maintenance services.
- Implementing new applications to meet new or changing requirements.
- Increasing complexity – replacing obsolete systems with more effective systems that deliver greater functionality and are more complex than the old systems. In such instances, the new systems increase efficiency by eliminating certain manual processes and/or by meeting new requirements that the old system could not address.

In other words, increases in the IT operational budget are indicative of purchasing new technologies or expanding the usage of existing technologies.

Q. What types of new or expanded systems are you implementing?

A. Examples of new or expanded technologies include:

- New software to host the Western Energy Imbalance Market (Western EIM). This system was been discussed at length in PGE's previous general rate case, Docket No. UE 319, PGE Exhibit 300.
- Increased monitoring and visibility tools associated with IT operations and cybersecurity including network analysis, threat monitoring, and security analysis;
- A new Residential Energy Analysis Program (Opower), provided by Oracle. This program will be replacing PGE's current Energy Tracker program, which is no longer supported by the software provider.

- Microsoft Office 365 service fees plus additional deployment of Microsoft software. PGE has moved this application to the cloud because it is the most effective strategy to maximize functionality and speed. I discuss cloud services in more detail in Section III below.
- Planned expansion of process intelligence (PI) software for energy asset monitoring and analysis.
- Increased deployment of our security event and incident management tool.
- New software to support better internal control monitoring.
- Oracle Customer Care and Billing software for the new customer information system and meter data management system. These systems comprise PGE's Customer Touchpoints project discussed in detail in PGE Exhibit 900, Section III. The Customer Touchpoints project is the largest and final component of PGE's Customer Engagement Transformation program, which is also the final component of PGE's overall 2020 Vision initiative.

Q. Please provide a brief description of the 2020 Vision initiative.

A. 2020 Vision was a roughly ten-year initiative to implement a set of projects that would collectively modernize and consolidate our technology infrastructure. The ultimate purpose was to replace a multitude of existing software applications with fewer "enterprise" applications that provide integrated functionality for PGE's operations. Because 2020 Vision entailed a number of projects over many years, PGE discussed it at length in the following general rate cases: Docket Nos. UE 215 (2011, PGE Exhibit 600), UE 262 (2014, PGE Exhibits 600 and 900), UE 283 (2015, PGE Exhibits 700 and 1000), UE 294 (2016, PGE Exhibits 600 and 900), and UE 319 (2018, PGE Exhibits 500 and 900). As noted above, PGE Exhibit 900 discusses the final phase (Customer Touchpoints) of 2020 Vision.

Q. If one of the goals of the 2020 Vision initiative was to replace numerous applications with fewer enterprise systems, why would PGE's maintenance agreement costs increase?

A. As the number of applications decrease through consolidation, PGE experiences an increase in the maintenance agreement costs associated with: 1) new and more effective enterprise applications with greater functionality; and 2) expanded use of existing applications. The increase in maintenance fees is especially pronounced as we replace homegrown software, which requires no maintenance expense other than internal labor to provide support. Further, the replacement applications are not only greater in size and complexity because they are enterprise applications, but they also provide greater functionality than the systems they are replacing. Consequently, maintenance fee costs are increasing as a result of 2020 Vision.

B. Network Resiliency Project

Q. What are PGE's forecasted costs for the Network Resiliency Project?

A. PGE forecasts a total of approximately $15.0 million in network resiliency capital costs. The costs are projected over a three-year project lifecycle as follows: $6.0 million in 2018, $6.5 million in 2019, and $2.5 million in 2020. In addition to updating and modernizing the network, PGE will also have to operate and maintain it, the cost for which we forecast to be approximately $2.0 million annually beginning in 2019. These costs are currently forecast as non-labor O&M in the test year forecast.

Q. Please describe the Network Resiliency Project.

A. Network Resiliency is a current project to update and modernize the IT network in order to meet PGE's growing business and security needs as well as the demands of a changing IT environment, which together are resulting in an exponential growth in data flow and expanding number of system interfaces.

Q. Please define "IT network".

A. An IT or computer network, also called a data network, is a series of points or nodes, interconnected by communication paths for the purpose of transmitting, receiving and exchanging data, voice, and video traffic. In a complex system like PGE's, a network provides communication services for systems (e.g., computers, servers, applications, databases, phones, generation sites) that exchange information. The network is equivalent to a highway system that directs or routes traffic. The network moves data much like a highway facilitates the movement of vehicles. It provides the "road" on which data travels to send work orders to line crews to restore customer outages, to connect customers to our website to make payments, or to allow external Western EIM Operators to turn up a turbine at a PGE generation plant. The network is one of the most important and integral parts of IT, on which our systems rely to support PGE's business. It is also a key component to protect and secure the data and systems, and how they are used.

The network not only has to be robust enough to handle the increasing magnitude of data flow, but it also has to be flexible enough to cope with more frequent changes and new requirements. Business initiatives like the Western EIM and Customer Touchpoints rely on a network that is reliable, flexible, secure, and provides business continuity. The network links applications, users, and other systems (e.g., bank transfers). Without a properly functioning network, applications cannot be accessed, which, as these systems have become more critical to our operations, would result in the business's inability to function.

Q. Why does the existing network need to be updated and modernized?

A. PGE's current network has reached a point where it will not meet PGE's business units' requirements or needs. The increased use of IT systems to run PGE's business, including the heavy reliance on data, has pushed the demands on the network to be faster and more flexible. Just like the ever-increasing dependence many people have on their home connection to the internet, PGE's business needs have been increasing, which require a faster and more reliable network. The current network also cannot keep up with constantly increasing cyber security threats. Because the network has evolved over time, network security is complex and difficult to maintain. The updated and modernized network will provide a more secure and flexible security platform.

Expanding on the road analogy, the current network is like a road that was built for a certain level of traffic, a given size of cars and trucks, and so many interchanges for on and off traffic. As the number of vehicles and their size increases, and as more interchanges are built, the old road will become inadequate to the demands. Traffic that used to flow freely becomes mired in congestion. The updated and modernized network is then analogous to the road being widened significantly and the interchanges being redesigned to allow smoother flow. In summary, the current network design has limitations associated with flexibility and scalability, which detracts from our ability to modernize PGE's information systems and applications.

Q. What are the specific benefits of network resiliency?

A. Network resiliency will provide increased reliability, flexibility, and mobility to the business and to our customers. Using updated network technology, security can be configured and maintained for sensitive data in any PGE data center or external provider (e.g., cloud provider). This foundation work will create a resilient network where hardware failure will not stop applications from being available to customers. The new technology will be flexible to enable expansion of current or future data centers by allowing application mobility without a complete rebuild of the application. Additionally, the new network design will enable movement of applications to new facilities, public cloud, or private cloud offerings. This is accomplished by maintaining security policies that move with applications.

In addition, the Network Resiliency Project represents a network that is: modular to reduce total system failures, flexible to reduce the impact to business functions, and reliable to deliver excellent customer service. If PGE's IT department can keep systems functioning during a major event, then our employees can perform their jobs and help restore power as quickly as possible to our customers. The new network design will enable reduction of impacts across the enterprise, and enhance resiliency to improve business continuity for business and customer applications. The new design is also intended to support future improvements and upgrades of PGE data centers, increasing bandwidth requirements, ability to support cloud offerings, business continuity, and improved information security.

Q. Have any PGE systems already benefited from network resiliency improvements?

A. Yes. Numerous systems and applications have benefited from network resiliency work including PortlandGeneral.com, web payment, the interactive voice response system, and our customer service applications. Each of these provides critical information and services to PGE customers.

C. Information Security Program

Q. By how much do you expect non-labor IT O&M costs to increase due to PGE's Information Security Program?

A. From 2017 actuals to the 2019 forecast, non-labor IT O&M costs will increase by approximately $10.1 million to perform the necessary activities of the Information Security Program.

Q. Please describe PGE's Information Security Program.

A. PGE's Information Security Program began in 2017 and is a multi-year effort to maintain the security, reliability, and safety of our computers, control systems, and other cyber assets that help operate the grid, from cyber vulnerabilities. This project enables safe, resilient power delivery to our customers while maintaining a collaborative and integrated approach to security.

Q. What is the basis of this program?

A. As discussed in UE 319 (PGE Exhibit 500), PGE hired outside consultants to conduct a comprehensive review of our Information Security Program and one of their primary recommendations was to create a centralized, enterprise-wide security operations center, with detailed steps to achieve that goal. In response, PGE developed the Information Security Roadmap,[3] which we provide as confidential PGE Exhibit 602. PGE continually updates its Information Security Roadmap to address the changing information security environment.

[3] This was previously referred to as the Cyber Security Roadmap, but has evolved and been renamed.

Q. What is the difference between the Information Security Roadmap and Program?

A. The Information Security Roadmap is the multi-year plan that IT has developed and continues to update in order to specify the initiatives needed to address the information security risks and threats. The Information Security Program is the governance structure that implements the roadmap initiatives.

Q. What are the primary components of the Information Security Program?

A. There are five primary components of our Information Security Program:

- Risk-based Decision Making – to anticipate business needs, understand business risks and maintain our security expertise in order to provide clear and timely reporting of security risks to drive decision making.
- Coordinated Incident Response – to proactively deter, detect, delay, and respond to threats associated with operational technology, informational technology, and physical security.
- Integrated Security Operations – to proactively monitor and respond to physical, informational, and operational security threats.
- Culture of Security – to educate and maintain a vigilant workforce that is able to operate securely.
- Customer Satisfaction and Safety – to act as a responsible steward of customer information and secure the assets that protect customers, employees, and shareholders.

Q. What types of risks is PGE addressing with the Information Security Program?

A. The electric industry is continually being targeted in more sophisticated and complex attacks against operational technologies and traditional corporate systems. The most significant threats are posed by nation-state groups such as Russia, North Korea, and China. The following examples serve to emphasize the nature of these threats:

- Russian hacking organizations have become more advanced in their capabilities, as displayed with the compromise of a Wolf Creek Nuclear Operating Corporation power station near Burlington, Kansas.[4]
- A Michigan utility experienced an attack that resulted in a ransom payoff.[5]
- A 2016 Verizon breach report demonstrates a direct correlation between an Incident Command System being compromised and a cyberattack against SCADA[6] platforms.[7]

Q. How many cyber threats does PGE encounter per year?

A. PGE experiences nearly 300 million attacks per year. In fact, 2017 was the first year PGE has been able to accurately track the total number of such attempts. This capability is a direct result of instituting the Information Security Program, wherein the increased staff and technology investments have enhanced PGE's ability to identify and respond to these threats. We expect the number of attacks to continue to increase over time, as we increase visibility into threat environments and position our defensive protections more effectively.

Q. How specifically is PGE addressing the increasing threats related to information security?

A. By continuing to identify and evaluate the threats, and modify the Information Security Program accordingly, we are building our capabilities that include threat management, vulnerability management, and increasing the visibility into PGE's operations. It is our

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[4] https://www.nytimes.com/2017/07/06/technology/nuclear-plant-hack-report.html.
[5] https://www.wsj.com/articles/how-a-u-s-utility-got-hacked-1483120856.
[6] Supervisory control and data acquisition.
[7] http://www.verizonenterprise.com/resources/reports/rp_data-breach-digest_xg_en.pdf.

customers' expectation that we not only provide safe reliable power, but that we also protect their information. Data breaches, such as the numerous significant ones that occurred in 2017[8] are a primary focus for PGE's efforts in this area. In addition, we must continue to escalate our efforts to improve the security and operational reliability of PGE's critical infrastructure. While we are required by the Federal Energy Regulatory Commission to protect the Bulk Electric System, our efforts must continue well past these requirements and protect corporate (e.g., financial and customer) systems as well.

Q. Please describe the current key initiatives of the Information Security Roadmap.

A. The current key initiatives of the Information Security Roadmap include:

- Asset Discovery and Management – to identify and better understand PGE's hardware and software assets in order to the determine vulnerabilities in the technology environment.
- Vulnerability Management – to develop a comprehensive program that covers all assets and adequately detects and reports vulnerabilities in the assets to best identify risk.
- Identity and Access Management – to understand the lifecycle of user identity and access to systems. This will improve PGE's lifecycle governance including processes and tools to enable effective management.
- Incident Response – to define and develop an enterprise-wide incident response process and plan to efficiently and effectively respond to future potential incidents.

[8] https://www.identityforce.com/blog/2017-data-breaches.

- Business Impact Analysis (BIA) – to update planning based on: 1) the assessment and prioritization of critical PGE business functions and processes; and 2) the identification of potential business interruption risks and impacts. PGE will leverage the BIA to make informed process and capability improvements associated with disaster recovery to create a more resilient technology infrastructure.
- Security Awareness and Training – to strengthen and enhance an enterprise-wide security awareness program for all employees, and conduct targeted training for security staff.

Q. How do you prioritize the cybersecurity initiatives?

A. PGE uses a risk-based approach to prioritize information security initiatives. Understanding risk means understanding the relationship between:

- Vulnerability, such as a system with a known but unaddressed weakness.
- Threat, such as a bad actor propagating viruses or worms.
- Consequence, such as physical damage, loss of public safety, and/or financial loss.

A risk-based approach prioritizes components for protection, as well as the threats and vulnerabilities that require attention.

Q. You mentioned previously that PGE continually updates the Information Security Roadmap. Have there been changes to the Roadmap since PGE's previous rate case?

A. Yes. One of the more significant changes is accelerating the timeline to implement the remaining initiatives to address the full scope of recommendations. It is critical that we place our cyber security initiatives on a fast track for completion by 2020 due to increasing threats that we face on a daily basis.

Q. Why did you accelerate the implementation of your Information Security Roadmap?

A. PGE determined it was necessary to expedite the implementation timeline of our Information Security Roadmap in order to maintain the essential security, reliability, and safety of our systems. Cyber threats are increasing at an alarming rate and it has become evident that the longer timeframe to implement our Information Security Roadmap would significantly increase PGE's risk of incurring a serious cyber-attack. As grid technology evolves, so do threats to its integrity. While PGE has spent significant effort increasing its cyber security capabilities in recent years, our intent is to stay abreast of increasing cyber threats and implement the corresponding best practices to prevent those threats from circumventing PGE systems. As PGE continues to implement new tools, conduct risk assessments, vulnerability assessments, and penetration tests, we better understand our cyber risks.

D. IT O&M Labor

Q. Please describe the change in IT O&M labor costs.

A. From 2017 to 2019, we project that IT O&M labor costs will increase from approximately $20.2 million to $28.1 million. This increase occurs although:

- Total IT full time equivalent employees (FTEs) are flat – 304.3 FTEs in 2017 and 306.7 FTEs in 2019.
- Total IT labor costs do not increase at a rate greater than PGE's overall rate of escalation.

Q. To what, then, do you attribute this increase in IT O&M labor?

A. From 2017 to 2019, IT is experiencing a decline in capital labor due to the elimination of approximately 50 IT positions assigned to work on the Customer Touchpoints capital project that is being completed in 2018. This reduction in capital labor is replaced by increasing O&M labor, the elements of which are as follows:

- Approximately $4.1 million for ongoing annual support of the completed Customer Touchpoints systems.
- Approximately $2.4 million for increased O&M labor associated with the Information Security Program efforts described above. In short, some of the information security costs are capitalized and some are charged to O&M in accordance with generally accepted accounting principles.

III. Emerging Technology

Q. Is PGE currently evaluating an emerging technology for potential changes to its technology environment?

A. Yes. Although cloud computing is not a new concept, over the years cloud-based services have significantly matured and stabilized to the point where they represent a viable technology platform.

Q. What is cloud computing?

A. Traditionally, organizations with an IT presence hosted applications and services in-house (also known as on-premises) and provided internal services directly to customers and employees. With cloud computing, this operating model evolves to a shared-services and shared-infrastructure environment, enabling an organization to reduce its on-premises IT footprint in favor of internet-based and internet-enabled products and services that operate on a subscription basis.[9] Cloud computing offers the ability to vastly scale computing power, flexibility, and availability. It also offers many flexible service models that are responsive to dynamic business needs.

Q. What services does the cloud offer?

A. Common cloud service models include:

- Infrastructure as a service – virtual machines and other low-level services are provided to the customer in place of physical hardware. This service is good for quickly ramping up and down infrastructure.

[9] PGE's definition of cloud computing aligns with the National Institute of Standards and Technology (NIST) publication SP 800-145. See PGE Exhibit 600 Work Papers for a copy of the NIST document.

- Platform as a service – applications and database services are provided without access to the underlying operating systems and hardware. Portlandgeneral.com is a good example of platform as a service.
- Software as a service – the service provider delivers the application without access to lower level components. PGE's recent deployment of Microsoft Office 365 is an example of this cloud-based technology.

Q. What are the benefits of the cloud?

A. Cloud based services have the potential to provide PGE with a new level of flexibility in how we manage and organize our IT capabilities, and improve provisioning of service. Utilizing cloud-based services instead of traditional data center services provides more stability and predictability for costs (i.e., with the burden of maintenance shifted to cloud providers, costs become more predictable over time). Additionally, migrating functions to the cloud results in more rapid scaling to meet increased customer and business demands. The benefit to customers is realized through the ability to develop, deploy, and maintain new and existing applications more quickly and effectively than is currently possible. This directly supports PGE's efforts to listen, lead, and adapt to our customer expectations and enables us to evolve the way we do business along with a rapidly evolving technology landscape. PGE will be able to strategically develop, deploy, and maintain new and/or existing applications more quickly, with more flexibility, cost savings, increased reliability, minimized down time, and enhanced security.

Q. How is PGE currently using cloud computing?

A. As noted by the examples above, PGE has several applications that have been successfully migrated to cloud-based services, including our time collection system (myTime), the customer-facing website (portlandgeneral.com), and email services (Microsoft Office 365). Over time, PGE expects to move an increasing number of applications to the cloud as it becomes a more viable alternative to in-house computing. Current initiatives that are developing cloud-based applications include the Human Resource Optimization Program, IT Service Management, perimeter and endpoint security services, customer energy usage analysis, energy recovery analysis, crisis management, and Microsoft suite migration.

Q. Will PGE move more applications to cloud-based computing?

A. Yes. Eventually we will be moving toward more cloud-based computing to the extent that it offers a number of advantages including improved delivery time, better disaster recovery, and simplified configuration management. Several of our neighbor utilities including Arizona Public Service, Pacific Gas &Electric, and Southern California Edison are actively expanding their investment in cloud-based services. Ultimately, we plan to take a measured and careful approach to cloud-based computing that effectively weighs the costs, benefits, and risks of comparable systems.

IV. Summary and Conclusions

Q. Please provide a summary of your testimony.

A. As PGE moves to more technology-based operations, the costs for operating and maintaining our IT systems will not only increase, but so will the costs to provide the necessary level of information security. Consequently, the test year forecast reflects the costs needed to accomplish the 2019 portion of this on-going transition. More specifically, the increase in IT O&M costs from 2017 actuals to the 2019 test year forecast is the result of four primary drivers which I summarize as follows:

- Hardware and software maintenance agreements – these costs are a necessary aspect of functioning hardware and software systems because they provide: 1) appropriate licenses for the needed number of users; 2) access to vendor-provided fixes and patches to keep the systems operational; and 3) regular upgrades to correct programming errors and maintain continued technical maturity.
- Network resiliency – these costs support PGE's project to update and modernize the IT network in order to meet PGE's growing business and security needs as well as the demands of a changing IT environment. Due to the exponential growth in data flow and expanding number of system interfaces, PGE's existing network has reached a point where it will not meet these needs or have the flexibility to meet new requirements. Without a properly functioning network, applications cannot be accessed, which, as these systems have become more critical to our operations, would result in the business' inability to function.
- Information Security – these costs will allow PGE to maintain the security, reliability, and safety of our computers, control systems, and other information

assets that help operate the grid from cyber vulnerabilities. Because of the magnitude and sophistication of attacks and the expectation that they will only expand over time, PGE has enhanced its efforts to address these threats in order to maintain the essential security, reliability, and safety of our systems.

- Labor costs – these costs reflect: 1) the completion of PGE's Customer Touchpoints project, which has reduced IT labor that will be charged to capital; and 2) an offsetting increase in IT O&M labor used to operate and maintain the Customer Touchpoints systems as well as perform certain activities associated with the Information Security Program. In spite of these changes, IT FTEs remain flat from 2017 to 2019 and overall IT labor costs increase at a very moderate level.

Q. What do you specifically request of the Commission?

A. I request that the Commission approve the IT-related costs that PGE has included in its 2019 test year forecast. These costs are appropriate and necessary to continue the transition to more technology-based operations.

V. Qualifications

Q. Please describe your qualifications.

A. I received a Bachelor of Science Degree in Business Administration and Computer Science from Oklahoma State University. My employment with PGE started in January 2018, as the Interim Vice President and Chief Information Officer. Prior to that, I served for over a decade as Executive Vice President and Chief Information Officer at the Bonneville Power Administration. I have held other leadership and management positions at WaferTech (Camas, WA), Mitsubishi Silicon (Salem, OR), and Sun Refining and Marketing (Philadelphia, PA). I have served on the advisory board of EnergySec, and on the Electric Sector Coordinating Council, focusing on cyber security improvements across the federal sector and the electric utility industry. I have served as a member of UNITE electric utility consortium of CIOs, and have held a Federal Top Secret Security Clearance from the Department of Energy, since 2008.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
601	Summary of IT Costs
602C	Information Security Roadmap

IT Summary by Operating Area

Function	2015 Actuals	2016 Actuals	2017 Actuals	2018 Forecast	2019 Forecast	2019-2017 Delta	Annual % Delta 2017-2019
Production							
Direct	264	254	284	-	-	(284)	
Allocated	7,264,124	9,557,999	9,488,192	10,351,792	13,242,601	3,754,409	18.1%
IT Deferral	312,972	312,972	312,972	312,971	-	(312,972)	
Total Production	7,577,359	9,871,224	9,801,447	10,664,763	13,242,601	3,441,154	16.2%
Power Operations							
Direct	1,022,349	1,011,868	1,131,388	1,741,991	1,811,106	679,718	26.5%
Allocated	1,772,266	1,492,874	1,229,314	2,572,951	3,048,341	1,819,027	57.5%
IT Deferral	-	-	-	-	-	-	
Total Power Ops	2,794,615	2,504,742	2,360,702	4,314,942	4,859,447	2,498,745	43.5%
Transmission							
Direct	301,316	595,346	336,288	849,037	905,296	569,008	64.1%
Allocated	1,470,604	1,407,217	1,248,931	1,701,175	2,170,720	921,789	31.8%
IT Deferral	56,099	56,099	56,099	56,099	-	(56,099)	
Total Transmission	1,828,018	2,058,662	1,641,318	2,606,310	3,076,016	1,434,698	36.9%
Distribution							
Direct	981,509	3,388,577	3,309,027	4,101,971	4,319,390	1,010,363	14.3%
Allocated	17,722,661	20,826,809	24,847,843	26,583,499	33,920,877	9,073,034	16.8%
IT Deferral	415,443	415,443	415,443	415,443	-	(415,443)	
Total Distribution	19,119,613	24,630,829	28,572,314	31,100,913	38,240,267	9,667,954	15.7%
Customer Svc							
Direct	3,742,323	2,751,874	3,060,158	9,053,399	9,070,386	6,010,229	72.2%
Allocated	13,434,747	14,072,169	15,072,179	15,543,512	19,833,715	4,761,536	14.7%
IT Deferral	527,466	527,466	527,466	527,466	-	(527,466)	
Total Customer Svc	17,704,536	17,351,509	18,659,803	25,124,377	28,904,101	10,244,299	24.5%
A&G							
Direct	996,930	423,274	665,351	11,691	11,988	(653,363)	-86.6%
Allocated	10,565,799	11,975,293	11,816,014	12,617,309	16,139,740	4,323,726	16.9%
IT Deferral	424,821	424,821	424,821	424,821	-	(424,821)	
Total A&G	11,987,550	12,823,388	12,906,186	13,053,822	16,151,728	3,245,542	11.9%
Totals							
Direct	7,044,691	8,171,193	8,502,496	15,758,089	16,118,167	7,615,671	37.7%
Allocated	52,230,200	59,332,360	63,702,473	69,370,238	88,355,995	24,653,521	17.8%
IT Deferral	1,736,800	1,736,800	1,736,800	1,736,800	-	(1,736,800)	
Totals by Operating Area	61,011,692	69,240,354	73,941,770	86,865,128	104,474,162	30,532,392	18.9%
Labor Adjustment	-	-	-	(988,147)	(1,666,230)	(1,666,230)	
Adjusted Grand Total	61,011,692	69,240,354	73,941,770	85,876,981	102,807,932	28,866,162	17.9%

Exhibit 602C

Protected Information Subject to Protective Order 18-047

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bradley Jenkins
Stefan Cristea

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Bradley Jenkins. My position at PGE is Vice President, Generation and Power Operations. I am responsible for all aspects of PGE's power supply portfolio, power operations, and generation.

My name is Stefan Cristea. My position at PGE is Regulatory Analyst in the Rates and Regulatory Affairs department.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the operations and maintenance (O&M) expenses associated with PGE's long-term power supply resources. We discuss the recent plant performance of our generation fleet. We also identify and discuss the major drivers of the 2019 test year O&M expenses related to PGE's generating plant operations as compared to actual 2017 O&M expenses.

Q. What are PGE's goals for generating plant O&M?

A. Our primary goals for plant-related activities are to manage our generating plants in a safe, reliable, and economically competitive manner, while maintaining compliance with all local, state, and federal regulations, permits, licenses, and environmental standards. We achieve these goals by implementing prudent and timely maintenance practices, establishing effective safety and reliability initiatives, and making the necessary investments in our plants.

Q. How is the remainder of your testimony organized?

A. Our testimony has five additional sections. In Section II, we discuss PGE's generation resources and their recent performance. In Section III, we discuss our forecast of 2019 test year generation O&M expenses. Section IV provides a description of operation and maintenance activities at Boardman prior to ceasing coal operations at the end of 2020. We then summarize our request in this filing in Section V and our qualifications are in Section VI.

II. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit that identifies all of PGE's power supply resources for the 2019 test year?

A. Yes. Confidential PGE Exhibit 701 lists PGE's generating resources and their expected average energy output as modeled under normal hydro conditions for PGE's initial 2019 Net Variable Power Cost (NVPC) forecast.[1]

Q. Have PGE's long-term power supply resources changed significantly since the 2018 general rate case filed in Docket No. UE 319 (UE 319)?

A. No.

B. Plant Performance

Q. What are PGE's goals for generation plant performance?

A. The performance and availability of PGE's generating resources are top priorities for the Generation organization. As a long-term goal, we target plant performance and availability in the top quartile of industry peers. On a year-to-year basis, realized plant availability is a key factor in evaluating the Generation organization.

Q. How did PGE's thermal plants perform in 2017?

A. In 2017, although experiencing longer than planned maintenance outages, the majority of PGE's thermal plants continued to perform well, and maintained a relatively high availability. Thermal generation in 2017 was slightly lower than historical levels for some of our thermal plants due to an above-normal hydro year, major inspections, and unplanned maintenance work. In addition, the Boardman generating plant was economically displaced

[1] PGE Exhibit 300 provides PGE's 2019 NVPC forecast and supporting documentation.

in the spring (March through June) and fall (November) due to increased hydro availability and low natural gas prices.[2]

Confidential PGE Exhibit 702 provides historical 2014 through 2017 thermal plant availability and forced outage rates reported quarterly by PGE to the North American Electric Reliability Corporation (NERC), and finalized annually.[3]

Q. How does the 2019 expected generation for PGE's thermal resources compare to previous years?

A. Confidential PGE Exhibit 706 provides actual thermal generation for 2015, 2016, and 2017, and PGE's current 2019 forecast for each of our thermal resources. Thermal generation is expected to increase in 2019 relative to 2017, primarily due to weather normalization and forecasted lower fuel prices, which we expect to contribute to increased dispatch.

[2] Boardman is currently off-line due to a cracked turbine rotor that was causing high vibrations. The turbine has been removed and we are in process of awarding a bid to fix the damaged piece. PGE estimates the plant will be back online by June 1, 2018.

[3] Forced Outage Rates reported to NERC are not equivalent to the forced outage rate methodology applied in PGE's NVPC forecast. See PGE's Minimum Filing Requirements included as part of PGE's NVPC forecast for details on the forced outage rate methodology employed in MONET.

III. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What is your 2019 test year forecast of generation O&M expenses?

A. Our test year forecast of generation O&M expenses is approximately $147.6 million excluding Information Technology (IT). This represents a $7.7 million increase over 2017 actuals. Table 1 below summarizes these costs, which are adjusted to remove emissions control chemical costs.[4]

Table 1
Generation Plant O&M Summary ($ millions)*

O&M Expenses	2017[5] Actuals	2019 Test Year	Delta 2017 vs 2019	Annual % Change 2017 vs 2019
Labor	$43.1	$44.5	$1.4	1.6%
Non-Labor	$83.3	$86.9	$3.6	2.1%
Major Maintenance Accruals	$13.4	$16.1	$2.7	9.5%
Subtotal Generation O&M	**$139.9**	**$147.6**	**$7.7**	**2.7%**
Information Technology	$12.2	$18.1	$5.9	22.0%
Total	**$152.1**	**$165.7**	**$13.6**	**4.4%**

**May not sum due to rounding.*

Q. How is labor and non-labor generation O&M expected to change from 2017 actuals to 2019 forecast?

A. We project labor-related generation O&M to increase by approximately $1.4 million. This increase is due to labor cost escalations[6] and an increase in the number of full time equivalent employees (FTEs) as discussed below. In addition, we project non-labor related generation O&M, including Major Maintenance Accruals (MMAs), to increase by approximately $6.3 million. Section B below summarizes the major drivers of these increases.

[4] Emissions control chemicals expenses are considered power costs and included in our 2019 NVPC forecast.
[5] See PGE Exhibit 700 work papers (“2019 GRC - Production O&M WP Actuals”, tab “Summary”) for the variance between 2017 actuals and 2018 budget.
[6] PGE Exhibit 400 provides additional information regarding labor escalations.

Q. What do IT costs represent in Table 1?

A. IT costs here represent expenses that are directly assigned or allocated to generation and relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, and communication systems. Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 600.

B. Generation O&M Major Drivers

1. Non-Labor O&M Expenses

Q. What are the main drivers for the changes in non-labor generation O&M expenses?

A. The main drivers for the change in non-labor O&M expenses are: 1) updated 2019 MMA estimates;[7] 2) Environmental and Licensing Services (ELS) expense; and 3) non-labor cost escalations.

Q. Which thermal plants have MMAs included in your 2019 test year plant forecast?

A. PGE will have MMAs for Port Westward 1 and 2, Coyote Springs 1, Carty, and Colstrip 3 & 4 (PGE share).

Q. What is the increase in total MMA expenses?

A. The 2019 test year MMA expense charged to generation O&M is forecasted to increase by approximately $2.7 million over 2017 actual maintenance expenses.[8] However, as reflected in PGE Exhibit 703, 2019 forecasted MMA expense is only $0.8 million higher than the MMA amounts currently in base rates. The increase in 2019 MMA expense is due to cost

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[7] See PGE Exhibit 705, pages 14 – 15, for a detailed explanation of the MMA calculation methodology provided in Docket No. UE 319, PGE Exhibit 700, Section III, part C.

[8] As reflected in PGE Exhibit 703, the net MMA increase in 2019 when compared to 2017 actuals and including MMA amounts recorded in Other Revenue (Account 4560002) is $2.2 million.

escalations and slightly higher maintenance expenses expected to occur beginning in 2018.[9] PGE Exhibit 703 provides MMA estimates for specific PGE thermal plants.

Q. Why do you discuss ELS in the Production O&M testimony?

A. ELS provides support to all of PGE's facilities, and, in particular, to our generation facilities. ELS is responsible for required compliance and other regulatory activities including monitoring wildlife, fishery operations, Federal Energy Regulatory Commission (FERC) hydro license requirements, air quality, and waste management.

Q. What is PGE's forecast for ELS non-labor O&M expenses in 2019?

A. PGE forecasts generation-related ELS non-labor expenses to be approximately $5.7 million in 2019. Table 2 below provides a summary of ELS non-labor generation O&M by functional area.

Table 2
Generation Related ELS Non-Labor Budget ($ millions)*

	2017 Actuals	2018 Budget	2019 Test Year	Delta 2017 vs 2019	Delta 2018 vs 2019
West Side Hydro	$1.8	$2.1	$2.3	$0.5	$0.2
Pelton-Round Butte	$2.2	$2.5	$2.5	$0.3	$0.0
Generation Support/Other	0.4	$0.9	$0.9	$0.6	$0.0
Total	**$4.4**	**$5.5**	**$5.7**	**$1.4**	**$0.2**

**May not sum due to rounding*

Q. What are the primary causes for the increase in PGE's ELS non-labor O&M expenses?

A. The projected increases in ELS O&M expenses are primarily due to: 1) more work related to environmental restoration projects at PGE's West Side Hydro plants; 2) additional reporting and compliance costs associated with other generation facilities; and 3) cost delays in 2017

[9] See PGE Exhibit 700 non-confidential work papers ("2019 GRC MMA Work Paper") for plant-specific MMA detailed calculations.

related to certain road maintenance projects and compliance activities specified in the FERC licenses for our hydro generation plants.

However, as shown in Table 2 above, when comparing ELS 2019 forecasted expenses to the ELS 2018 budget, the increase is only approximately $0.2 million.

Q. Why are ELS expenses increasing at PGE's West Side Hydro plants?

A. ELS expenses are increasing due to work that is related to the major environmental restoration projects required by our FERC license. The FERC license requires PGE to continue in 2019 with the Clackamas Lower River Shade Enhancement and Gravel Augmentation Programs.

Q. Please describe the Clackamas Lower River Shade Enhancement Program.

A. PGE is undertaking this riparian shading program to reduce the heat load from direct sunlight on the lower Clackamas River and improve fish and wildlife habitat. Streamside trees shade the stream and its riparian area, resulting in lower in-stream temperatures as less sunlight reaches the water. This temperature control measure is one of the measures required by the FERC license[10] to be implemented along 30 miles of the lower Clackamas River and its tributaries.

Q. Why do the Clackamas Lower River Shade Enhancement expenses increase in 2019?

A. Expenses increase in 2019 due to the shift from primarily capital costs to O&M expenses. The first part of the project entails six years (2013-2018) of active planting and maintenance that was approximately 67% capital expenditure and 33% O&M expenses. The second part of the project consists of an additional two years (2019-2020) for the maintenance program

[10] The measures required by Oregon Department of Environmental Quality under the FERC license are habitat restoration in the lower Clackamas River, channelizing Faraday Lake and associated draw down during summer months, and 30 miles of riparian shade program.

that is 100% O&M. The increase in the O&M expense ratio from 33% in 2017 to 100% in 2019 results in an overall increase of approximately $0.3 million in O&M expenses related to the Clackamas Lower River Shade Enhancement Program.

Q. Please describe the Clackamas Lower River Gravel Augmentation Program.

A. The FERC license at PGE's West Side Hydro Projects also requires PGE to continue placing gravel along the Clackamas River below the River Mill facility in 2019. PGE must place approximately 8,000 cubic yards along the river bank the first year, and as much as 20,000 cubic yards in subsequent years.[11] The gravel will mitigate the impact of PGE's three main-stem dams, which block the migration of alluvial material (e.g., gravel) that provides important habitat for fish spawning and other aquatic organisms. The O&M portion of the project includes the excavation, hauling, placement of gravel along the river, and monitoring the effects of the augmentation required by our permits and the FERC license.

PGE initially scheduled the program to be implemented between 2016 and 2019. However, low river flows prevented moving sufficient amounts of gravel in 2016 such that FERC approved PGE's request to begin the project in 2017 with implementation to occur between 2017 and 2020. In 2017, the initial phase of the project was deemed successful as the entire quantity of 8,000 cubic yards of gravel material that was placed on the river bank migrated into the river within a month.

[11] The amount that must be placed along the river each year is determined by how quickly the gravel migrates into the river and what the ongoing monitoring reflects on how the eroding gravel is affecting conditions below the dam.

Q. Why are the Clackamas Lower River Gravel Augmentation Program expenses increasing in 2019?

A. Expenses are increasing in 2019 because the amount of gravel that will be placed on the river bank will be 2.5 times that in 2017 (i.e., approximately 20,000 cubic yards), resulting in more work and monitoring of the river bed gravel layer and requiring an increase of approximately \$0.13 million in projected 2019 O&M expenses.

Q. With regard to the second driver of additional reporting and compliance by ELS, please explain the \$0.6 million increase related to Generation Support & Other?

A. Part of the variance (\$0.25 million) is due to an increase in the Tucannon River Wind Farm environmental compliance expenses related to avian protection. In 2018 and 2019, PGE is required to perform an Environmental Fatality Study as part of the on-going work related to the Bald and Golden Eagle Protection Act Take Permit.[12] Additionally, in support of other generation sites, ELS expenses are increasing due to the proposed Cleaner Air Oregon air toxics regulations and changes in greenhouse gas reporting requirements that are anticipated to require additional reporting and compliance costs. The Cleaner Air Oregon program[13] is the Oregon Department of Environmental Quality (ODEQ) proposal to change the basis of its air quality program to include risk-based air toxic limits and, in preparation for this program, ODEQ has requested air permit holders to submit additional information on various constituents. The additional information required by the ODEQ goes above and beyond the requirements of the federal Environmental Protection Agency's (EPA)

[12] See https://www.fws.gov/midwest/midwestbird/eaglepermits/bagepa.html for additional information.
[13] See http://www.oregon.gov/deq/aq/cao/Pages/default.aspx for additional information.

Hazardous Pollutants Program. The ODEQ is scheduled to take action on the new regulations in July 2018.[14]

Q. With regard to the third driver of cost increases for ELS, why were costs delayed in 2017?

A. Approximately $0.24 million of ELS costs initially projected for 2017 were delayed until 2018 and 2019 because:

1. High spring run-off made several Deschutes River study sites inaccessible, and we were not able to complete field work required by the Pelton-Round Butte FERC license as part of the Fish Passage Plan that needs to be developed annually.[15] The field work is tied to biological activities that only occur during specific times of year. For example, if river flows are high when redband trout are spawning, then we have to wait a year for the next opportunity to conduct the study.
2. Sockeye adult returns were low due to their lifecycle, out-migrant numbers, ocean conditions, and high river flows, reducing the number of radio tags that we were required to purchase to monitor these fish. We expect increased sockeye adult returns in 2018 and 2019.
3. Because of high Deschutes River flows in 2017 we are to collect an additional year of data for the ongoing water quality study required by the FERC license for

[14] See http://www.oregon.gov/deq/Regulations/rulemaking/Pages/Rcleanerair2017.aspx and http://www.oregon.gov/deq/Rulemaking%20Docs/caotimeline.pdf for additional details.

[15] The Plan includes studies to determine fish passage, juvenile migration, juvenile rearing, densities, and habitat, adult migration, spawning and survival, adult upstream trap and haul, native fish monitoring water quality monitoring and large wood monitoring and placement. The Plan is reviewed by the Fish Committee which includes the regulatory agencies and some license signatories and is filed with FERC annually. If a portion of the work cannot be completed due to various issues, a report needs to be filed with FERC to provide the reasons behind it.

Pelton-Round Butte and reschedule for 2018 some modeling activities (laboratory analysis and follow-on modeling) that were initially planned for 2017.

4. Some maintenance projects on United States Forest Service (USFS) property were not completed in 2017 due to USFS fire closures.
5. Some road maintenance projects were delayed due to prioritization (based on FERC approved schedules) being given to other capital projects.[16]

Q. What is the increase in non-labor O&M expenses due to non-labor cost escalations?

A. Non-labor O&M expenses are forecasted to increase by approximately $2.2 million in the 2019 test year due to non-labor cost escalations. For non-labor costs, we use escalation rates ranging from 1.71% to 2.72% from *Global Insights*, Long-term Forecast dated August 2017. Non-labor cost escalation rates are presented in PGE Exhibit 200.

2. Labor O&M Expenses

Q. What is the change in generation-related FTEs from 2017 to 2019?

A. We project an increase of approximately thirteen generation FTEs between 2017 and 2019. However, all of this increase is expected to occur between 2017 and 2018 as we complete the hiring that we described in UE 319.[17] PGE Exhibit 704 provides the hiring status of the generation-related FTEs PGE requested in that docket.

Q. Are any of the FTEs budgeted in 2018 incremental to PGE's request in UE 319?

A. Yes. PGE is adding four additional FTEs at Trojan beyond its 2018 request filed in UE 319.

[16] These projects are the Oak Fork Campground renovation and Lake Harriet Campground and Day Use area renovation.

[17] PGE Exhibit 705 provides consolidated FTE information from Docket No. UE 319: 1) UE 319, PGE Exhibit 700, Section III, part B, 2 at pages 8 - 11; 2) UE 319, PGE Exhibit 702 at pages 22-24; 3) UE 319, PGE Exhibit 1900 at pages 28 - 42; and 3) UE 319, PGE's responses to OPUC Data Request Nos. 619, 626, and 673 at pages 44-70.

Q. Why is PGE adding four additional Trojan FTEs?

A. These FTEs are required to perform security, operation and maintenance, and administrative functions. PGE has been working with the Nuclear Regulatory Commission (NRC) to determine security staffing that meets their recommendation and industry standards. At the time we filed our 2018 general rate case, the NRC Trojan site assessment was not yet completed. NRC's final assessment concluded that the addition of seven Trojan Independent Spent Fuel Storage Installation (ISFSI) technicians is warranted to provide appropriate security staffing at Trojan. PGE requested three of these FTEs in UE 319 and filled the positions in 2017. We expect the four remaining vacant positions to be filled by the end of 2018. PGE's share of the costs associated with these FTEs is expected to be reimbursed to PGE customers through Schedule 143-Spent Fuel Adjustment via the settlement claim with the Department of Energy for the Trojan ISFSI, approved by the U.S. Court of Federal Claims on July 18, 2013.

IV. Boardman Decommissioning

Q. Why will coal operations at Boardman cease at the end of 2020?

A. In 2009, the Oregon Regional Haze Plan and Oregon Utility Mercury Rule set forth additional pollution control requirements for Boardman, requiring PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing plant operations and replacing Boardman with a new source of supply. During the 2009 Integrated Resource Plan (IRP) process (Docket No. LC 48), several alternatives were evaluated and PGE's final recommendation was to cease Boardman coal operations at the end of 2020.

Q. Was PGE's recommendation acknowledged by the Public Utility Commission of Oregon (Commission)?

A. Yes. The Commission acknowledged PGE's 2009 IRP, including Boardman's ceasing coal operations in 2020, through Commission Order No. 10-457, on November 23, 2010.

Q. How is PGE recovering Boardman accelerated depreciation and decommissioning costs?

A. Commission Order No. 10-478 authorized PGE to establish an automatic adjustment clause (Schedule 145) under ORS 757.210 to recover increased depreciation and decommissioning expenses associated with the early closure of Boardman. Schedule 145 became effective on January 1, 2011.

Subsequently, the Commission authorized PGE to begin collecting accelerated depreciation/amortization expense and decommissioning costs related to the change in

Boardman closure date under Schedule 145 through Commission Order No. 11-242.[18]

Q. Will ceasing coal operations affect PGE's O&M practices at Boardman in 2019 and 2020?

A. Boardman O&M practices will not change substantially. PGE's main goals will continue to be maintaining high levels of availability and reliability while simultaneously ensuring the safety of our plant personnel.

Q. Please provide a brief description of maintenance practices at Boardman.

A. PGE schedules one major maintenance outage every year at Boardman and for the remainder of the year, PGE performs preventive and corrective maintenance as needed. The goal for Boardman with regard to maintenance is to have 70% preventive maintenance and 30% corrective maintenance. Preventive maintenance is scheduled periodically according to how critical the equipment is for plant operations and to prevent equipment failure, while corrective maintenance is only performed if plant equipment fails.

Q. What operations are usually performed during preventive maintenance?

A. Preventive maintenance regularly schedules inspections, tests, repairs, and replacement of components in critical equipment. These maintenance practices aim to extend equipment life, reduce premature equipment failures, and increase equipment availability.

Q. How will maintenance practices for Boardman change in the plant's final two years of coal operation?

A. Maintenance practices at Boardman will not change substantially as the plant needs to maintain high availability to support PGE's load when needed. However, PGE will more

[18] Beginning in 2014 (via Docket No. UE 262), PGE moved the collection of accelerated depreciation associated with the early closure of Boardman from Schedule 145 into base customer prices. PGE continues to collect accelerated decommissioning costs through Schedule 145.

closely review the frequency of upcoming preventive maintenance to make sure that it is required given the shorter operating life of the plant. In addition, the plant management team will review all proposed major work to determine if it is required to keep the plant available as needed.

V. Conclusion

Q. Please summarize your request for generation O&M in this filing.

A. We request that the Commission approve PGE's 2019 forecast of $165.7 million in generation O&M costs (including IT generation-related expenses). This represents a $13.6 million increase from 2017 costs due primarily to non-labor costs escalation, increases in IT costs, updates to thermal plants MMAs, increases in ELS expenses related to PGE generation, and labor O&M expenses.

VI. Qualifications

Q. Mr. Jenkins, please describe your qualifications.

A. I hold a Bachelor of Science degree in Industrial Engineering from Southern Illinois University and have over 25 years of nuclear and thermal generation plant experience in operations, maintenance, refueling, and construction. I am a certified Project Management Professional and have worked for Entergy, Energy Northwest and contracted with Tennessee Valley Authority. I joined Portland General Electric (PGE) in 2012 as Operations Manager at the Boardman coal plant and became the plant manager in 2013. I was promoted to General Manager, Diversified Plant Operations in 2014, overseeing all of PGE's thermal and renewable assets in eastern Oregon and Washington. In September 2015, I became Vice President of Power Supply Generation and in October of 2017, I was appointed Vice President of Generation and Power Operations. Today, I oversee our power supply portfolio, operations, and over 3000 MWs of wind, solar, hydro, and thermal generation at 17 generation facilities, as well as the Trojan ISFSI.

Q. Mr. Cristea, please describe your qualifications.

A. I received a Bachelor of Arts degree in Regulatory Economics from the University of Calgary, Alberta, Canada. I accepted my current role at PGE in 2016 and worked on PGE's last general rate case (UE 319). Previously, I worked as an Operations Coordinator for Enterprise Holdings in Calgary, Canada, overseeing the operations of approximately 50 car-rental offices. Prior to that, I owned and managed a construction business in France.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
701C	PGE Generating Resource Summary
702C	PGE Thermal Plant Forced Outage Rate and Availability 2014-2017
703	PGE Thermal Plant Major Maintenance Accruals
704	Docket No. UE 319 FTEs Hiring Status
705	Docket No. UE 319, PGE Exhibit 700, 702, 1900, and PGE's Responses to OPUC Data Request Nos. 619, 626, and 673
706C	PGE Actual and Forecasted Thermal Generation

Exhibit 701C

Protected Information Subject to Protective Order 18-047

Exhibit 702C

Protected Information Subject to Protective Order 18-047

Major Maintenance Accruals (MMAs) by PGE Thermal Plant						
Plant	2017 actuals (A)	2018 GRC (UE 319) (B)	2019 FILE (C)	2019 GRC revised (D)	Variance 2017-2019 revised (D-A)	Annualized Variance 2018 GRC-2019 GRC (D-B)
Carty	5,402,219	4,988,552	5,140,311	5,492,363	90,144	503,811
Coyote	3,745,872	3,363,349	3,363,346	2,638,544	(1,107,328)	(724,805)
PW1	5,123,816	5,120,517	5,120,515	5,574,585	450,769	454,068
PW2	967,602	544,811	544,813	826,853	(140,749)	282,041
Colstrip	-	2,580,408	2,580,408	2,868,710	2,868,710	288,302
Total	**15,239,509**	**16,597,637**	**16,749,393**	**17,401,055**	**2,161,546**	**803,417**

MMAs by PGE Accounts						
PGE Accounts	2017 actuals (A)	2018 GRC (UE 319) (B)	2019 FILE (C)	2019 GRC Revised (D)	Variance 2017-2019 revised (D-A)	Variance 2019 FILE-2019 Revised (D-C)
MMAs in Account 4560002 (Other Revenue)*	1,809,924	1,405,570	1,283,381	1,283,381	(526,543)	-
MMAs in Generation O&M Accounts	13,429,585	15,192,067	15,466,012	16,117,674	2,688,089	651,662

**MMAs recorded in Other Revenue reflect the differences between forecasted MMAs and each plant's budgeted maintenance expenses in a certain year. If plants' budgeted maintenance expenses are higher than the plant MMA, a credit will be applied to Other Revenue. Conversely, if budgeted maintenance expenses are lower than the plant MMA a debit will be recorded in the Other Revenue account.*

PGE Exhibit 200 (Revenue Requirement) MMA Adjustment[1]

2019 FILE	2019 REVISED	Adjustment
16,749,393	17,401,055	651,662

1. Total MMA amounts in Generation O&M Accounts and Account 4560002 (Other Revenue)

PGE Exhibit 700 (Generation O&M) MMA Adjustment[2]

2019 FILE	2019 REVISED	Adjustment
15,466,012	16,117,674	651,662

2. Includes only Generation O&M Accounts

Dept.	Dept. Description	Description	UE 319 FTE Request	Hiring Status as of EOY 2017	2019 GRC FTE Request
GENERATION			32.0		13.0
16	Power Operations	Energy Market Settlement Analyst	2.0	Hired	0.0
16	Power Operations	Energy Market Policy Analyst	1.0	Hired	0.0
62	Trojan	Independent Spent Fuel Storage Installation (ISFSI) Technician	3.0	Hired	4.0
86	Port Westward 2	Generation Technician	3.0	Hired	0.0
88	Carty	Generation Technician	1.0	Hired	0.0
161	Pelton-Round Butte	Maintenance Supervisor	1.0	Hired	0.0
Various	Beaver	Temporary Hourly Positions	3.0	Hired	0.0
551	Power Supply Engineering Svcs	Surveyors	3.0	Reorganization from Property Services completed/ filled	0.0
551	Power Supply Engineering Svcs	Cyber Security Engineer	1.0	Not hired / Projected for 2018	1.0
551	Power Supply Engineering Svcs	Cyber Security Analyst	1.0	Not hired / Projected for 2018	1.0

*4 Additional Trojan FTEs added in 2018 per NRC site assesment

551	Power Supply Engineering Svcs	Compliance Specialist	1.0	Not hired / Projected for 2018	1.0
551	Power Supply Engineering Svcs	Analyst	1.0	Not hired / Projected for 2018	1.0
551	Power Supply Engineering Svcs	IT Analyst	1.0	IT position removed	0.0
551	Power Supply Engineering Svcs	Admin Specialist	1.0	Reorganization completed / filled	0.0
551	Power Supply Engineering Svcs	Technical Writer Specialist	1.0	Hired in December 2017 / Appears as an FTE increase from '17 to '18	1.0
554	Generation Projects	Project Manager / Senior Project Engineer	1.0	Hired	0.0
556	Integrated Resource Planning	Analyst	3.0	Not hired / Projected for 2018	3.0
556	Integrated Resource Planning	Project Manager	1.0	Not hired / Projected for 2018	1.0
841	Environmental and Licensing Services	Project Controls and Compliance Specialist	1.0	Hired	0.0
842	Eastside Biological Services	Technician, Environmental Communication	1.0	Hired	0.0
844	Environmental Compliance and Licensing	Environmental Specialist	1.0	Hired	0.0

UE 319 / PGE / 700
Jenkins – Rodehorst

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bradley Jenkins
Aaron Rodehorst

February 28, 2017

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Bradley Jenkins. My position at PGE is Vice President, Power Supply Generation. I am responsible for all aspects of PGE's Power Supply Generation. My qualifications are included at the end of this testimony.

My name is Aaron Rodehorst. My position at PGE is Senior Analyst, Regulatory Affairs. My qualifications are included at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the operations and maintenance (O&M) expenses associated with PGE's long-term power supply resources. We discuss the recent plant performance of our Generation fleet. We also identify and discuss the major drivers of the 2018 test year O&M expenses related to PGE's generating plant operations as compared to actual 2016 O&M expenses.

Q. What are PGE's goals for plant operations and maintenance?

A. Our primary goals for plant-related activities are to manage our Generation plants in a safe, reliable, and economically competitive manner while maintaining compliance with all local, state, and federal regulations, permits, licenses, and environmental standards. We achieve these goals by implementing prudent and timely maintenance practices, establishing effective safety and reliability initiatives, and making necessary investments in our Generation plants.

Q. How is the remainder of your testimony organized?

A. Our testimony has four additional sections. In Section II, we discuss PGE's Generation resources and their recent performance. In Section III, we discuss our forecast of 2018 test year Generation O&M expenses. We then summarize our request in this filing in Section IV and present Mr. Jenkins' qualifications in Section V.

II. PGE's Generation Resources

A. Generation Resources

Q. Have you prepared an exhibit that identifies all of PGE's power supply resources for the 2018 test year?

A. Yes. Confidential PGE Exhibit 701 lists PGE's generating resources and their expected average energy output as modeled under normal hydro conditions for PGE's initial 2018 Net Variable Power Cost (NVPC) forecast.[1]

Q. Have PGE's long-term power supply resources changed significantly since the UE 294 general rate case?

A. Yes. In Order No. 15-356, Docket No. UE 294, the Public Utility Commission of Oregon approved the addition of the Carty Generating Station (Carty) in customer prices, if placed into service by July 31, 2016. PGE met that deadline when Carty went into service on July 29, 2016.

B. Plant Performance

Q. What are PGE's goals for Generation plant performance?

A. The performance and availability of PGE's generating resources are top priorities for the Generation organization. As a long-term goal, we target plant performance and availability in the top quartile of an industry peer group. On a year-to-year basis, realized plant availability is a key factor in evaluating the Generation organization.

Q. How have PGE's thermal plants performed in 2015 and 2016?

A. In 2015, the majority of PGE's thermal plants experienced no major forced outages and exhibited high availability. Thermal Generation was higher than normal for most of our

[1] Discussed in PGE Exhibit 300

thermal plants due to low natural gas prices and the timing of hydro availability. Because of a warm spring in 2015, runoff came earlier than normal and did not coincide with the summer peak, requiring increased dispatch of thermal facilities to meet loads.

In 2016, the majority of PGE's thermal plants continued to perform very well, experienced no major forced outages, and maintained a high availability. Similar to 2015, we had mild winter and spring temperatures at the beginning of the year causing the economic displacement of the Boardman generating plant. Towards the end of 2016, high amounts of rain led to increased hydro availability displacing the majority of our thermal resources.

Confidential PGE Exhibit 704 provides historical 2013 through 2016 thermal plant availability and forced outage rates reported quarterly by PGE to the North American Electric Reliability Corporation (NERC), and finalized annually.[2]

Q. Were there any exceptions in 2015 and 2016?

A. Yes, just one plant. Beaver generating plant's forced outage rate is higher in 2015 and 2016 due to unplanned maintenance work:

- In 2015, Unit 3 had an unplanned hot gas path inspection following a routine inspection, Unit 6 experienced excessive internal oil leaks requiring immediate troubleshooting and repair, and Unit 7 (steam turbine) had excessive vibration on the generator requiring disassembly and repair of the end blocking of the rotor windings.
- In 2016, Unit 2's Major Inspection was extended due to discovery work identified during repairs creating an unplanned outage extension, Unit 7 (steam turbine)

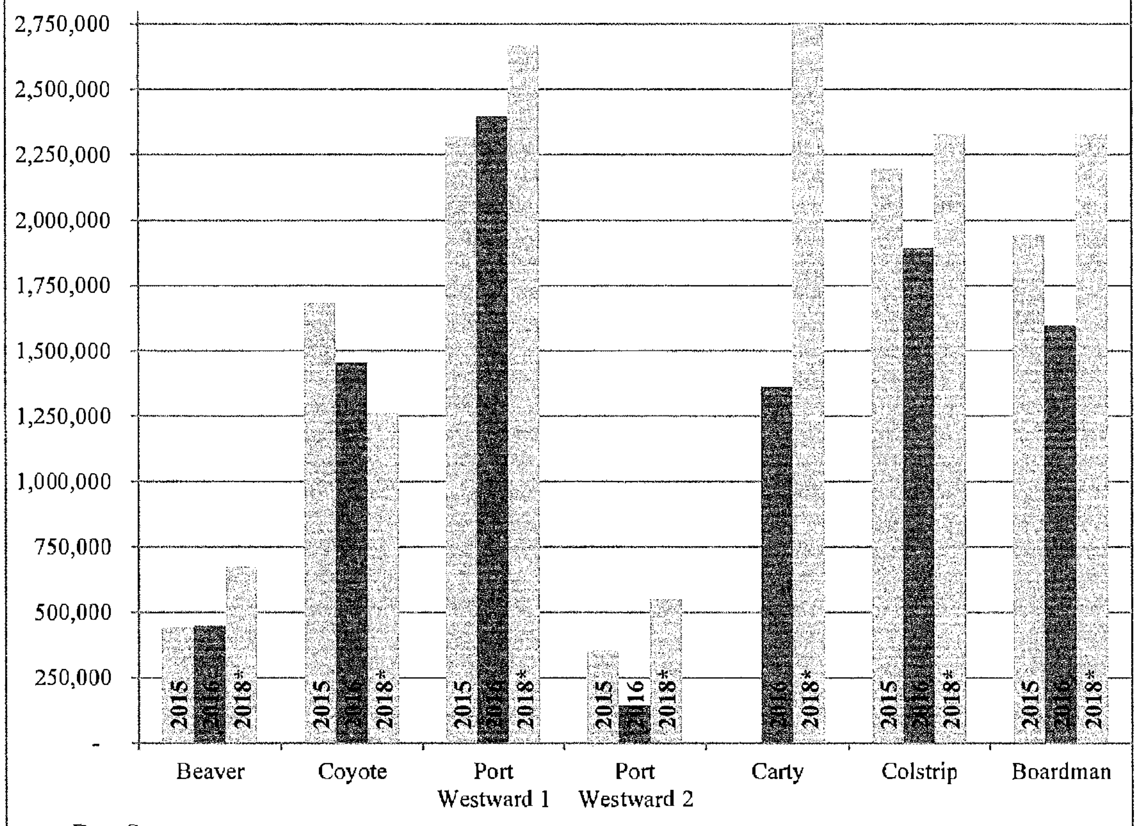
[2] Forced Outage Rates reported to NERC are not equivalent to the forced outage rate methodology applied in PGE's Net Variable Power Cost (NVPC) forecast. See PGE's Minimum Filing Requirements included as part of PGE's NVPC forecast for details on the forced outage rate methodology employed in MONET.

experienced vibration issues requiring a rebalancing, and Unit 8 was forced out most of the year due to compressor damage and evaluation of repairs.

Q. How does the 2018 expected Generation for PGE's thermal resources compare to previous years?

A. Figure 1 below summarizes actual thermal Generation for 2015 and 2016, and PGE's current 2018 forecast for each of our existing thermal resources. Thermal Generation is expected to increase for our thermal resources in 2018 relative to 2016, primarily due to weather normalization and forecasted low fuel prices, which we expect to contribute to increased dispatch. PGE Exhibit 300 presents our 2018 NVPC forecast.

Figure 1: PGE Thermal Resource Generation (MWh)



Data Source:
*2018 based on initial NVPC forecast presented with this filing
2016 based on the 2016 EGR&D YTD Report presented in Docket No. UM 1294 (Monthly Power Cost Report)

III. Generation Plant O&M

A. Generation Plant O&M Expenses

Q. What are the changes in PGE's plant O&M between 2016 and 2018?

A. Table 1 below summarizes the changes in total Generation Plant O&M expenses. These amounts include adjustments for emissions control chemical costs.

Table 1
Generation Plant O&M Summary
($millions)*

O&M Expenses	2016 Actuals	2018 Test Year	Delta	Annual % Change
Labor	$39.4	$43.3	$3.9	4.8%
Non-Labor	$81.5	$85.6	$4.1	2.5%
Major Maintenance Accruals	$12.1	$16.3	$4.2	16.0%
Subtotal	$133.0	$145.1	$12.1	4.5%
Information Technology (IT)	$12.4	$14.6	$2.3	8.7%
Total	**$145.4**	**$159.8**	**$14.4**	**4.8%**

**May not sum due to rounding.*

Q. How do labor and non-labor plant O&M expenses change from 2016 to 2018?

A. Labor-related plant O&M is projected to increase by approximately $3.9 million. This increase is due to labor cost escalation (discussed in PGE Exhibit 400) and an increase to the number of Full Time Equivalent employees (FTEs) discussed below. Non-Labor related plant O&M, including the Major Maintenance Accruals (MMA), is projected to increase by approximately $8.3 million. The major drivers of these increases are summarized in Section B below.

Q. What do IT costs represent?

A. IT costs represent expenses that are directly assigned and allocated to Generation and that relate to PGE's efforts to develop, operate, and maintain our computer, information, cyber, and communication systems. IT costs are allocated to all operating areas of the company and discussed in detail in PGE Exhibit 500.

B. Generation Plant O&M Expense Major Drivers

1. Non-Labor O&M Expenses

Q. What are the major drivers to non-labor O&M expenses?

A. The major drivers to non-labor O&M expenses are: 1) the increase in Carty O&M expenses, 2) updates to PGE's Major Maintenance Accruals, and 3) non-labor cost escalations.

Q. Please explain the increase in Carty O&M expenses.

A. Carty O&M expenses are estimated to increase by approximately $0.9 million due to the plant being operational for the full year 2018. In 2016, Carty began operations on July 29. Customer prices, however, already reflect Carty's full year budget in accordance with Commission Order No. 15-356.

Q. Please explain the increase in Major Maintenance Accrual (MMA) expenses.

A. PGE's MMA benefits to customers, calculation methodology, and expenses are discussed in detail in Section C below.

Q. What is the increase in non-labor O&M expenses due to non-labor cost escalations?

A. Non-labor O&M expenses are forecasted to increase by approximately $3.1 million in the 2018 test year due to non-labor cost escalations. For non-labor costs, we use escalation rates ranging from 1.66% to 3.11% from *Global Insights, Economic Outlook* dated August 2016. Non-labor cost escalation rates are presented in PGE Exhibit 200.

2. Labor O&M Expenses

Q. What is the change in Generation related FTEs from 2016 to 2018?

A. The projected increase in FTEs is approximately thirty-two across Generation.

Q. What are the main drivers for the increase in Generation-related FTEs?

A. The main drivers of the increase in Generation-related FTEs between 2016 and 2018 are as follows:

- Ten Power Supply Engineering Services (PSES) FTEs. These FTEs will 1) support increasing regulatory requirements, 2) work on PGE's aging assets requiring upgrades and/or replacement, and increased engineering support to maintain aging infrastructure, 3) develop expanded technical expertise needed as new forms of generation are added and control systems are modernized, and 4) ensure that PGE maintains a strong cyber security program. It is important for PGE to fill these positions in 2017 and 2018 to ensure that PGE's capital investments are utilized in an effective and beneficial manner and to allow PSES to properly manage the workload necessary to meet regulatory compliance and cyber security best practices.
- Four Resource Planning FTEs. These FTEs will provide increased support for strategic projects, Renewable Portfolios, and Integrated Resource Planning (IRP). If Resource Planning does not fill these positions, the impacts include, but are not limited to, reduced productivity and quality, long delays in regulatory processes, and reduced opportunity for stakeholder involvement.
- Three Trojan FTEs. These FTEs will support increased Trojan security per Nuclear Regulatory Commission (NRC) Security requirements. PGE is working with the NRC to implement a security staffing that meets their recommendations and industry standards. The NRC has recently completed its assessment of our plan and its conclusions are being disseminated. As a result of the timing, actual staffing may differ from the one submitted for the OPUC review in our 2018 general rate case filing. Nearly all costs associated with these FTEs are reimbursable to PGE through

the settlement claim with the Department of Energy for the Trojan Independent Spent Fuel Storage Installation, approved by the U.S. Court of Federal Claims on July 18, 2013.

- Three Environmental and Licensing Services FTEs. These FTEs will support the increased demands of regulatory compliance, FERC license implementation requirements, and increased outreach requirements related to our fisheries program per the Pelton-Round Butte Fish Committee recommendation.
- Twelve Generation plant and Power Operation FTEs. These FTEs will increase the number of operating crews at Port Westward and support Generation projects, PGE's participation in the Western Energy Imbalance Market (EIM)[3] starting in 2017, and increased plant operations and maintenance for Carty, Pelton-Round Butte, and Beaver.

Additional detail by FTE is provided in PGE Exhibit 702.

Q. Please summarize the FTEs requested for PSES.

A. PSES provides civil, electrical, mechanical engineering, and survey services to PGE's generating plants and related departments. PSES also provides various forms of administrative support, such as records management, drawing control, and project design. As a result of adding new assets (Port Westward II in 2015 and Carty in 2016), continually expanding cyber security, regulatory and reporting requirements, and aging Generation resources, PSES requires six additional FTEs for administrative, engineering, and analyst positions. Four additional FTEs result from the reorganization of surveyors from Property

[3] Discussed in PGE Exhibit 300, Section III, Part C

Services to PSES in the middle of 2016 and the transfer of an Admin Specialist from Hydro Operations to PSES in 2018.[4]

Q. Please summarize the position additions in Resource Planning.

A. The IRP process has materially changed from a cyclical process to one that requires an ongoing level of support. In the past the process was cyclical and involved a two-year planning cycle, in which heavy analysis and documentation was completed in the first year, followed by a less intense stakeholder review process in the second year. The emergence of variable energy in increasing quantities and the portfolio effects between all resources have created new challenges for resource planning and system operators. As a result, the IRP process has evolved to incorporate new resource types, characteristics, and relationships. PGE must increase staffing to be able to keep pace with the complexity of the analysis, communicate information to stakeholders, maintain continuity, and ensure appropriate individual workloads.

Q. Please summarize the remaining FTE additions in Generation.

A. The remaining additional FTEs relate to increased environmental regulatory compliance and license implementation requirements, generating plant operation support, other compliance requirements (e.g., Trojan Independent Spent Fuel Storage Installation), and PGE's participation in the Western EIM. As noted above, detailed information by FTE is provided in PGE Exhibit 702.

[4] The four FTEs transferred from Property Services and Hydro Operations represent a net zero FTE impact company wide and will have no incremental costs to customers.

C. Major Maintenance Accruals

Q. Please explain the major maintenance accrual (MMA) included in fixed O&M costs.

A. Major maintenance costs can vary dramatically from year to year and, absent an MMA, PGE would expense the major maintenance costs in the period the work is performed. Accounting for costs in this manner has two significant drawbacks: 1) it does not allow the recording of expense in the same period the benefits[5] occur; and 2) it results in an expense that is cyclical and "lumpy" over the years. Due to this, it can be problematic to establish stable prices. To avoid these problems, the Commission approved in Docket No. UE 93 (Order No. 95-1216) an accrual and balancing account treatment for major maintenance costs.[6] The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-year period. By balancing the costs and collections, PGE achieves an appropriate matching of costs to both the period and customers benefitted. The accrual also results in a better matching of costs with revenue, without requiring PGE to file a rate case every year to capture the swings in major maintenance costs.

Q. How does the MMA benefit customers?

A. Properly matching the major maintenance expense to the period of operation benefits customers by reducing intergenerational inequities in prices to customers. In addition, normalizing the costs reduces the frequency of rate changes because it eliminates the need to

[5] The benefits are the generation and use of electricity by customers

[6] Order No. 95-1216 approved an MMA for Coyote Springs. Subsequent Commission orders approving MMAs include: PW1 (UE 262, OPUC Order No. 13-459), PW 2 (UE 283, OPUC Order No. 14-422), and Carty (UE 294, OPUC Order No. 15-356)

file nearly annual rate cases or deferred accounting applications to capture the significant increases or decreases in major maintenance costs.

Q. What items are included in the MMA?

A. Major maintenance events occur based upon maintenance intervals established under the company's plant maintenance contracts. Generally, the timing is dependent upon a facility's capacity factor (hours run / hours in period). Listed below are examples of natural gas Generation plants' major maintenance items:

- Major Turbine and Generator Inspections to perform advanced assessments, along with related work that may include combustion turbine alignment, exhaust frame modifications, repairs to thrust bearings, the generator stator and the generator field.
- Hot Gas Path Inspection including the disassembly of combustion and turbine sections of the combustion turbine so that parts may be inspected, and repaired or replaced as necessary. The combustion section is where the natural gas is combined with compressed air and burned. The turbine section is where mechanical energy is extracted from the high speed flow of hot combustion gases exiting the combustion chambers.
- SR Catalyst Replacements.
- Auxiliary Boiler Maintenance.

Q. How does PGE calculate the MMA?

A. We forecast five years of the expected operational run of our thermal plants using the MONET model and, based on hours of plant operation, we forecast the timing for the major maintenance activities. The total maintenance costs over the five year period are averaged to obtain the annual major maintenance expense.

Q. For which thermal plants are MMAs included in the 2018 test year plant O&M costs.

A. For the test year 2018 PGE will continue to have MMAs for Port Westward 1 and 2, Coyote Springs, and Carty. In addition to these, PGE is proposing an MMA for the Colstrip generating plant.

Q. Please explain PGE's proposal to create an MMA for Colstrip.

A. Colstrip Units 3 and 4 operate on a three-year maintenance outage schedule. This creates a pattern where maintenance outages occur in two of every three years leading to large variances in costs from one year to another. To address the cyclical and "lumpy" nature of these costs and for the other reasons discussed above we propose creating an MMA for Colstrip.

Q. What is the cost impact of creating an MMA for Colstrip?

A. Creating an MMA for Colstrip would increase the forecasted total MMA amount for the 2018 test year by approximately $2.3 million. However, we propose reducing the MMA amounts for our other thermal plants in the 2018 test year such that the net increase in total MMA after adding Colstrip would be less, or approximately $1.0 million.

Q. What is the total MMA amount included in the 2018 test year plant O&M costs?

A. The 2018 test year total forecasted MMA expense is $16.3 million, increasing by $4.7 million over 2016 actuals. The major drivers for this variance are the $2.7 million increase in the Carty MMA due to having the plant operational for a full-year in 2018 and the $2.3 million increase due to adding the Colstrip MMA. Similar to Carty non-labor O&M expenses, the increase in the Carty MMA has a minimal actual cost impact to customers because Carty's full annualized budget was placed in rates in accordance with Commission Order 15-356 (UE 294). Based on the current level of the balancing accounts for the MMAs and the latest five-year forecast for Coyote Springs and Port Westward 2 we reduced the annual accrual amounts by approximately $0.9 million, partly offsetting the increase due to adding the Colstrip MMA. Major maintenance accrual calculations are presented in PGE Exhibit 703.

IV. Conclusion

Q. Please summarize your request for Production O&M in this filing.

A. We request that the Public Utility Commission of Oregon approve PGE's forecast of $159.8 million in Production O&M costs in the 2018 test year. This represents a $14.4 million increase from 2016 costs due primarily to non-labor costs escalations, increases in plant and power operations O&M expenses, and labor O&M expenses.

V. Qualifications

Q. Mr. Jenkins, please describe your qualifications.

A. I hold a Bachelor of Science degree in Industrial Engineering from Southern Illinois University and have over 25 years of nuclear and thermal Generation plant experience in operations, maintenance, refueling, and construction. I am a certified Project Management Professional and have worked for Entergy, Energy Northwest and contracted with Tennessee Valley Authority (TVA). I joined Portland General Electric (PGE) in 2012 as Operations Manager at the Boardman coal plant and became the plant manager in 2013. I was promoted to General Manager, Diversified Plant Operations in 2014, overseeing all of PGE's thermal and renewable assets in eastern Oregon and Washington. I was appointed Vice President of Power Supply Generation in September of 2015. Today, I am responsible for over 3000 MWs of wind, solar, hydro, and thermal Generation at 15 Generation facilities, as well as the Trojan Independent Spent Fuel Storage Installation. I am also an Air Force veteran with 9 years of military experience as a Systems Analyst.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
701C	PGE Generating Resource Summary
702	PGE Full Time Employees Descriptions
703	PGE Major Maintenance Accrual Calculations
704C	PGE Thermal Plant Forced Outage Rate and Availability 2013-2016

EXHIBIT 701C

Confidential

Dept.	Dept. Description	Description	Basis for Position(s)	FTE
GENERATION				32.0
16	Power Operations	Energy Market Settlement Analyst	PGE will join the Western Energy Imbalance Market in the latter half of 2017 and the Market Operator will be sending PGE large settlement files on a frequent basis. Two additional FTEs are required to perform this work.	2.0
16	Power Operations	Energy Market Policy Analyst	Required to monitor the policy and rule changes implemented by the Western Energy Imbalance Market. The position will be needed early in 2017 to assist Market Trials prior to live participation in the Western Energy Imbalance Market in the latter half of 2017.	1.0
62	Trojan	Independent Spent Fuel Storage Installation (ISFSI) Technician	Required to perform security, operating, maintenance, and administrative functions at the Trojan ISFSI. The ISFSI technicians will report to the ISFSI Supervisor and are responsible for the safe storage of spent nuclear fuel from the Trojan Nuclear Plant. The ISFSI technicians are being added in response to recent NRC Security Inspector comments highlighting the need for additional staff to adequately cover security duties required in federal regulation. Nearly all costs are reimbursable to PGE through the DOE settlement claim for the Trojan ISFSI.	3.0
86	Port Westward 2	Generation Technician	Required to support progression from four to five operating crews and maintenance. Having the additional FTEs will also reduce the use of contractors during PW2 annual outages.	3.0
88	Carty	Generation Technician	To better align gas plants, a planner scheduler was added to all gas plants in 2015. That 1 FTE count was not added to Carty total head count resulting in Carty being one Generation Technician short. Adding this FTE is required to ensure that plant operations and maintenance are being done in an effective and efficient manner.	1.0
161	Pelton-Round Butte	Maintenance Supervisor	Pelton Round Butte operation and dispatch changed significantly over the past 5 to 10 years with the plant being cycled more frequently and seemingly relied upon more for ancillary services as opposed to primarily being base loaded in the past. This position is required to manage critical asset maintenance and coordinate maintenance support and outage planning services in support of plant operations.	1.0
Various	Beaver	Temporary Hourly Positions	Required to reduce overtime and are partially offset by savings from this reduction. Although the three temporary hourly positions appear to be an increase, this is because PGE opted to contract out the work these positions would have done in 2016. As such, 2016 outside services is over budget while temporary labor is under budget. PGE continues to expect to need this support and has budgeted three FTEs for 2018.	3.0
551	Power Supply Engineering Svcs	Surveyors	Reorganization of surveyors from Property Services to PSES in the middle of 2016. FTE impact is a net zero change company wide and will have no incremental cost to customers.	3.0

551	Power Supply Engineering Svcs	Cyber Security Engineer	With the additional and existing Industrial Control System (ICS) generation assets (i.e. assets that run plant generators), the ever increasing workload will require a deeper level of cyber security engineering support. The cyber engineer position is required to ensure PGE generation sites are able to respond to the ever changing cyber security threats. Each engineer is working to balance operational requirements with defending our current technologies from cyber-attacks.	1.0
551	Power Supply Engineering Svcs	Cyber Security Analyst	With the current cyber-attack rate at existing and future industrial Control System (ICS) generation assets, PGE has implemented capital projects associated with a Network Intrusion Detection System (NIDS). These recent software and hardware investments require an analyst position to tune and develop the NDIS system to ensure all PGE generation sites have proper protocols to respond to cyber-attacks.	1.0
551	Power Supply Engineering Svcs	Compliance Specialist	Required to assist in understanding, interpreting, communicating, and implementing PGE compliance with North American Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) regulatory standards.	1.0
551	Power Supply Engineering Svcs	Analyst	Required for additional support of PGE's new Reliability, Performance, and Monitoring (RPM) Center initiated in 2016. The RPM Center brings in house the plant and asset performance monitoring historically provided by General Electric's "Smart Signal" service. Additionally, the RPM Center will provide an extra level of vigilance as PGE begins more frequent cycling of generating plants.	1.0
551	Power Supply Engineering Svcs	IT Analyst	Will function as a dedicated generation resource for resolving IT issues at Generation facilities. With the ever expanding role of IT based systems at PGE, a dedicated resource is required to ensure that issues at remote Generation facilities are addressed in a timely manner.	1.0
551	Power Supply Engineering Svcs	Admin Specialist	transfer from Hydro Operations. FTE impact is a net zero change and will have no incremental cost to customers.	1.0
551	Power Supply Engineering Svcs	Technical Writer Specialist	Required to assist with the development and maintenance of over 200 generation procedures, including Generation Fleet, Environmental, Cyber Security, Compliance, Reliability, and plant specific procedures.	1.0
554	Generation Projects	Project Manager / Senior Project Engineer	Required to provide expertise for engineering reviews, project coordination, and project management. The Generation Project department is planning for the next five years while continuing to support current projects, intracompany requests for support of projects, and evaluation of new and evolving technologies to support future projects. In analyzing the timeline of the current IRP, currently proposed renewable RFP, and future RFPs, and the timeframe to develop new supply- and demand-side resources, Generation Projects has identified a gap in staffing that threatens the ability of the group to successfully deliver complex and strategic for our customers.	1.0

	Integrated Resource Planning	Analyst	Required to provide strategic and technical analysis, including economic evaluations or resource options needed to meet the electric energy needs of PGE customers. They will also provide analysis to support recommendation regarding several regulatory processes, including, but not limited to, the IRP and Competitive Bidding (RFP). With the increased workload due to the emergence of variable energy in increasing quantities and the portfolio effects between all resources, current employees are consistently working more than 40 hours per week affecting the work quality and significantly increasing the risk for mistakes. Additionally, important work is being deferred or dropped due to lack of bandwidth to complete critical tasks. Several options to fill the business needs, minimize impacts and overcome the challenges were evaluated, including contractors, sunset positions, cross-training, and long-term temporary positions. None provide the necessary support to maintain quality and efficiency over the long term.	3.0
556	Integrated Resource Planning	Project Manager	Required to facilitate management and coordination for the models to support evaluation of technologies, locational deployment and use cases for all resources, as well as development of the documentation and materials necessary to transparently communicate the information produced through the IRP and related process. Several options to fill the business needs, minimize impacts and overcome the challenges were evaluated, including contractors, sunset positions, cross-training, and long-term temporary positions. None provide the necessary support to maintain quality and efficiency over the long term.	1.0
841	Environmental and Licensing Services	Project Controls and Compliance Specialist	Required to develop, implement, research, and support project control for PGE's environmental projects, ensure their implementation in an economical manner, and coordinate compliance, communication and interaction among various PGE departments and groups. The position will also develop department budgeting and staffing strategy and schedules based on projected projects going through funding process.	1.0
842	Eastside Biological Services	Technician, Environmental Communication	The Pelton-Round Butte Fish Committee, comprised of 22 state and federal agencies and NGOs have raised concerns about the growing outreach needs related to our fisheries program, and that current staffing isn't sufficient to meet that without affecting the biological program. Currently there is an active adversarial group, the Deschutes River Alliance (DRA) on the Deschutes River that opposes the Pelton Round Butte fisheries and water quality program. DRA is currently suing PGE under the Clean Water Act. The DRA has a very active and effective public relations campaign. PGE's communication/PR hasn't been sufficient given the increased negative campaigning. This position was created to provide a dedicated person, located on the Eastside, to increase our outreach efforts in the community. Before this, the Eastside Biological staff tried to fill the gap, but this increased workload was interfering with their ability to complete FERC required tasks. The risk of not providing increased outreach is that DRA's influence would grow, adding other NGOs and community members to their supporters threatening PGE's investment in the Selective Water Withdrawal fish collection facility.	1.0

844	Environmental Compliance and Licensing	Environmental Specialist	Required for multi-media environmental support for eastside non-hydro generation sites (Biglow Canyon, Boardman, Carty, Coyote Springs, Tucannon), with emphasis on air quality and waste management. Increased regulations and activities include coal combustions residuals, ODEQ changes to air quality permitting, and general environmental support for generation facilities.	1.0

**Exhibit 703 is voluminous in size,
provided in electronic format only**

EXHIBIT 704C

Confidential

UE 319 / PGE / 1900
Jenkins – Rodehorst

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Bradley Jenkins
Aaron Rodehorst

July 18, 2017

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Bradley Jenkins. My position at PGE is Vice President, Power Supply Generation. I am responsible for all aspects of PGE's Power Supply Generation. My qualifications are included at the end of PGE Exhibit 700.

My name is Aaron Rodehorst. My position at the time of PGE's filing of the 2018 general rate case was Senior Analyst in PGE's Rates and Regulatory Affairs department. My qualifications are included at the end of PGE Exhibit 300. As of the second quarter of 2017, I am a Bidding Strategy Analyst in PGE's Power Operations department.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions taken by the Public Utility Commission of Oregon (OPUC) Staff (Staff) with respect to PGE's Production Operation and Maintenance (O&M) Full Time Equivalent Employees (FTEs) request for the 2018 test year. No other party raised issues related specifically to PGE's Production O&M FTE request for the 2018 test year.

Q. Please summarize your review of Staff's position regarding PGE's Production O&M FTE request for the 2018 test year.

A. PGE believes that Staff does not take into consideration the need for these additional FTEs to ensure PGE plant reliability, safety, and regulatory compliance. We provide counter arguments for each of Staff's FTE adjustments in Section II, below.

Q. Given Staff's position on Production O&M FTEs, what is your recommendation?

A. PGE agrees to reduce its request for Production O&M FTEs by one FTE. We oppose the removal of the remaining 12 FTEs requested because they are necessary for PGE to safely and reliably operate its generation units.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

II. Parties' Proposed Adjustments

A. Production O&M FTEs

Q. Please summarize Staff's proposal regarding Production O&M FTEs.

A. Staff proposed reducing PGE's Production O&M FTE request from 32 FTEs to just 19 FTEs.

Q. What was Staff's reasoning for the removal of 13 Production O&M FTEs?

A. Staff states that PGE's Production O&M labor needs do not justify the addition of these FTEs and there are no significant O&M cost reductions associated with them.

Q. Do you agree with Staff's reasoning?

A. No. PGE has presented extensive evidence for the Production O&M FTE request in our opening testimony (PGE Exhibits 700 and 702) and in our responses to numerous data requests from parties. For example, OPUC Data Request Nos. 525, 618, 619, and 626 asked about specific positions.[1] In addition, in response to OPUC Data Request No. 561, PGE compiled FTE information by project and prioritized Production O&M projects.[2] We summarize some of these arguments and also provide additional arguments in this testimony.

Q. Can you summarize the 13 Production O&M FTEs that Staff is proposing to remove?

A. Yes. Staff is proposing to remove the following positions:

- Three Trojan Independent Spent Fuel Storage Installation (ISFSI) Technicians;
- Three Port Westward 2 (PW2) Generation Technicians;
- One Carty Generation Technician;

[1] PGE's responses to OPUC Data Requests Nos. 525, 618, 619, and 626 are provided in PGE Exhibit 1901.
[2] PGE's response to OPUC Data Request No. 561 is provided in PGE Exhibit 1803.

- One Power Supply Engineering Services (PSES) IT Analyst;
- One PSES Technical Writer;
- One Generation Project Manager;
- One Eastside Biological Services Technician, Environmental Communication;
- One Environmental Compliance and Licensing Specialist; and
- One PSES Compliance Specialist.

We discuss each of these recommendations in detail below.

1. Trojan ISFSI Technicians

Q. Do you agree with Staff's proposal regarding the removal of the three Trojan ISFSI Technicians?

A. No. The Nuclear Regulatory Commission (NRC) assessment of the site noticed a need for additional security and recommended that PGE increase security at Trojan to comply with NRC security requirements. By not increasing the security at Trojan, PGE faces increased risk of non-compliance with NRC security requirements. The ISFSI technicians will perform security, operating, maintenance, and administrative functions, and will be responsible for the safe storage of spent nuclear fuel from the Trojan Nuclear Plant.

We note that PGE's share of the costs associated with these FTEs are expected to be reimbursed to PGE customers through Schedule 143-Spent Fuel Adjustment via the settlement claim with the Department of Energy (DOE) for the Trojan ISFSI, approved by U.S. Court of Federal Claims on July 18, 2013.

2. PW2 Generation Technicians

Q. Do you agree with Staff's proposal to remove three PW2 Generation Technicians?

A. No. We expect that PW2 will have significant increases in engine run time due to PGE's participation in the Western Energy Imbalance Market (Western EIM). The increased run time will require increased flexibility and increased staffing levels to dispatch the plant. In addition, the Wartsilla warranty's expiration at year-end 2016 will increase plant staff maintenance hours in 2017 and 2018, resulting in the need to transition to a five-shift rotation to control high operating overtime. If these FTEs are not added, plant Staff will have to work more overtime and thus will be more prone to injuries due to fatigue, which will in turn affect plant availability.

Q. Why does Staff recommend removing the PW2 Generation Technicians?

A. Staff claims that these FTEs should be removed because the cost of adding these FTEs outweighs the benefit and that "PGE's 2018 forecast for Port Westward maintenance overtime is not calculated correctly."[3]

Q. Do you agree with Staff's claims?

A. No. Staff states that "PGE over budgets for 2018 overtime by $280,000"[4] after comparing the 2018 forecasted overtime adjusted to reflect what Staff considers to be overtime cost reductions associated with adding the additional FTEs with the 2016 actual overtime expenses. Staff also asserts that "PGE claims that adding these FTEs will reduce overtime expense by $250,000 per year"[5], which is not correct. As noted in PGE's response to OPUC Data Request No. 626, part (d)(ii),[6] when comparing the 2017 O&M budget at Port Westward 1 (PW1) and PW2 to the 2018 forecast, PGE added additional generation technicians to provide sufficient operations support staffing that would allow for a five

[3] See Staff Exhibit 700, page 27-28.
[4] See Staff Exhibit 700, page 28, lines 5-6.
[5] See Staff Exhibit 700, page 27, lines 12-14.
[6] See PGE Exhibit 1901.

operating crew rotation. To cover the costs of these additional technicians from the 2017 budget to 2018 forecast, PGE *reduced* overtime expenses by approximately $50,000 and contract labor by approximately $200,000. Therefore, from the 2017 budget to the 2018 forecast the change in total labor costs is actually a decrease of $8,943 as shown in Table 1 below.

Table 1.

Labor Type	2017 Budget	2018 Forecast	2017-2018 Variance
PGE Labor	$2,177,286	$2,405,907	$228,621
Contract Labor	$273,497	$75,782	$(197,714)
Overtime	$481,543	$441,693	$(39,850)
Grand Total	**$2,932,325**	**$2,923,383**	**$(8,943)**

There is no decrease in labor costs (including labor, overtime, and contract labor) when comparing 2016 actuals to 2018 forecast. From 2016 actuals to 2018 forecast, PW1 and PW2 labor costs are projected to increase by approximately $156,511 or approximately 2.79% due to labor escalations.[7] In support of this testimony, PGE Exhibit 1904 provides the calculations of PW1 and PW2 total labor cost variances between 2016 actuals and 2018 forecast, and 2017 O&M budget and 2018 forecast.

3. Carty Generating Technician

Q. Do you agree with Staff's proposal to remove the Carty Generating Technician?

A. No. Carty and PW1 are similar plants and, as previously stated in PGE's response to OPUC Data Request No. 626, part (e),[8] Carty's estimated FTEs were based on the actual FTEs at PW1. PGE included this forecast as part of its Carty tracker filing forecast in Docket No. UE 294, which was subsequently approved by Commission Order No. 14-059. This forecast included 22.7 FTEs at Carty, but the plant came on-line at the end of July, 2016. Thus,

[7] See PGE Exhibit 1904, tab "PW Labor", cell E17.
[8] See PGE Exhibit 1901.

although budgeted and hired in 2016, this FTE is not fully reflected in 2016 calendar actuals. Adding the Generation Technician FTE at Carty will only align the FTE actual count at Carty with the plant's budget, with no incremental cost to customers.

Q. Did PGE already fill the Carty Generating Technician FTE?

A. Yes, this position was filled and the technician has been working at Carty in the planner scheduler function since August 2016.

4. PSES IT Analyst

Q. Do you agree with Staff's proposal regarding the removal of the PSES IT Analyst FTE?

A. Yes. This FTE was inadvertently recorded in two different departments during our test year preparation. The PSES IT Analyst added to PGE Department 551-PSES, is the same position as the Technical Specialist IV added to PGE Department 778-IT Business Relationship Management T&D and Generation Support.

5. PSES Technical Writer

Q. Do you agree with Staff's proposal regarding the removal of the PSES Technical Writer FTE?

A. No. Although Staff is correct that PGE has already developed 75 new common Generation Fleet Procedures, over 200 common Generation Fleet Procedures still need to be developed and maintained to align entire generation fleet to safety and reliability protocols. There is a pressing need for new safety, environmental, engineering, and cyber security procedures, including specific procedures to support PGE's participation in the Western EIM and for plant physical security. The common Generation Fleet Procedures and approximately 700 specific procedures will reside on the newly created SharePoint site that will be maintained by the technical writer. PGE anticipates that this technical writer will be able to develop five to ten new common Generation Fleet Procedures each year, as well as reduce the backlog of work over time. The technical writer is also required to review and update procedures, ensuring best practices and new regulations are incorporated. More information regarding Generation Fleet Procedures development, review, and update has been provided in PGE's response to OPUC Data Request No. 626, part (h), included in PGE Exhibit 1901 attached to this testimony.

Q. What is the risk if the PSES Technical Writer FTE is not added?

A. PGE would not be able to complete the Generation Fleet Procedures that still need to be developed. Not developing and maintaining these procedures would impact PGE's plant reliability and safety, cyber security, and increase the risk of not complying with regulatory requirements related to environmental services, engineering services, and plant specific operations and maintenance procedures.

6. Generation Project Manager

Q. Do you agree with Staff's proposal regarding the removal of the Generation Project Manager?

A. No. Removing the Generation Project Manager may significantly affect PGE's plant reliability and safety of personnel. Staff is accurate when stating that the current number of known generation projects that the Generations Projects group is expecting for 2018 is less than or the same as generation projects in previous years. However, the additional Generation Project Manager is needed as the group will also support the Integrated Resource Planning group, review qualifying facility applications, and evaluate technologies for pumped storage, geothermal, landfill gas, and other emerging technologies. In addition, the

Generation Project Manager will also be responsible for ongoing work related to hydro seismic upgrades to PGE's hydro facilities warranted after FERC examinations pursuant to Oroville Dam spillway damage.

6. Eastside Biological Services Technician, Environmental Communication

Q. Do you agree with Staff's proposal to remove the Eastside Biological Services Technician, Environmental Communication FTE?

A. No. PGE is in litigation with the Deschutes River Alliance (DRA) and PGE needs the Technician, Environmental Communication FTE to increase its efforts to provide information to nongovernmental organizations (NGOs) and the public on the Pelton-Round Butte license. The DRA opposes the Pelton-Round Butte fisheries and water quality program, and is suing PGE under the Clean Water Act. While this requested FTE is responsive to the litigation with DRA, the FTE is an ongoing need. The Pelton-Round Butte license requires a number of scientific studies, and the Clean Water Act, Section 401, Certification Conditions, provided as PGE Exhibit 1902, requires an outreach program be undertaken to communicate the results of these scientific studies that are underway. Pelton-Round Butte is a key facility for renewable integration for Oregon Renewable Portfolio Standard compliance and this position is required to ensure PGE fully complies with all license requirements and is able to respond to requests for information by NGOs.

Q. Does PGE agree with Staff's assertion that this FTE is requested to "repair its corporate image in the Pelton-Round Butte region"?[9]

[9] See Staff Exhibit 700, page 31, lines 6-7.

A. No. The Technician, Environmental Communication FTE was created to provide a dedicated person, located on the Eastside, to increase PGE's efforts related to our fisheries program for the reasons described above; this FTE will not "repair PGE's corporate image."

Q. Please summarize PGE's position regarding Staff's proposal to reduce the Eastside Biological Services Technician, Environmental Communication FTE?

A. PGE is opposing the reduction of this FTE. This FTE is necessary for PGE to meet the outreach and communications requirements outlined in the Pelton-Round Butte License, in addition to the requirements associated with the Low Impact Hydro Institute certification for Pelton-Round Butte Project, provided as PGE Exhibit 1903. In the long-term, this FTE will facilitate public communication at all of PGE's hydro, wind, coal, and natural gas generation facilities.

8. Environmental Compliance and Licensing – Environmental Specialist

Q. Do you agree with Staff's proposal regarding the removal of the Environmental Compliance and Licensing – Environmental Specialist FTE?

A. No. It appears that Staff is confusing PGE's generation plant-dedicated staff with corporate staff supporting PGE's operations. As previously stated in PGE's response to OPUC Data Request No. 618, included in PGE Exhibit 1901, the Environmental Specialist FTE is not a Carty plant-dedicated FTE and does not represent an increase in Carty plant staff.

Q. If this is not a Carty dedicated FTE, what support will this FTE provide?

A. The Environmental Specialist will be part of PGE Department 844 (Environmental Compliance and Licensing) and will provide support for all PGE's eastside non-hydro generation sites (Carty, Biglow Canyon, Boardman, Coyote Springs, Tucannon River) with emphasis on air quality and waste management.

Q. Why is this Environmental Specialist FTE necessary to be filled by 2018?

A. This position is required to be filled by 2018 to respond to changing regulations. Regulatory requirements and changes occur continuously, and the Oregon Department of Environmental Quality (ODEQ) is changing its air quality program to be based on air toxics. Regulatory changes are also occurring with regard to waste management and Coal Combustion Residuals. In addition to having to implement compliance with these changed rules, PGE will have to comply with avian protection requirements. All these new standards and rules will require a significant increase in compliance work for PGE, and ongoing and consistent support is needed to allow PGE to transition into compliance quickly as new rules are released.

9. PSES Compliance Specialist

Q. Do you agree with Staff's proposal regarding the removal of the PSES Compliance Specialist?

A. No. As with the Environmental Specialist FTE above, Staff appears to be confusing PGE's generation plant-dedicated staff and corporate staff in support of PGE's operations. The PSES Compliance Specialist is not a Carty plant-dedicated FTE and does not represent an increase in Carty plant staff.

Q. If this is not a Carty dedicated FTE, what support will this FTE provide?

A. As stated in PGE's response to OPUC Data Request No. 619, included in PGE Exhibit 1901, the PSES Compliance Specialist is required in the PSES department for additional support to PGE's North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) compliance efforts due to the addition of PW2, Tucannon River, and Carty generation plants between 2014 and 2016.

Q. Why is this PSES Compliance FTE necessary to be filed by 2018?

A. This position is required to meet NERC and WECC compliance requirements that require programs and standards to be developed and maintained for each plant. If this FTE is not added, PGE will face the risk of not meeting regulatory requirements since Critical Infrastructure Protection (CIP) compliance programs for generation would not be efficiently developed, overseen, and tracked.

III. Summary and Conclusion

Q. Please summarize Staff's position regarding PGE's Production O&M FTES.

A. Staff proposed a reduction of 13 FTEs to PGE's Production O&M FTE request for the 2018 test year claiming that PGE's Production O&M labor needs do not justify the addition of these FTEs and there is no significant O&M cost reductions associated with them.

Q. Please summarize PGE's position regarding Staff's proposed adjustments related to PGE's Production O&M FTEs.

A. PGE agrees to remove the PSES IT Analyst from its Production O&M FTE request. PGE however does not agree with any of Staff's other reductions related to PGE's Production O&M FTEs. Staff appears to disregard how PGE's generation plants reliability and safety would be affected by removing these FTEs. Staff is also ignoring the risks PGE would face with regards to compliance with CIP and NRC requirements. PGE believes that it has provided extensive details and proof supporting the need of these FTEs for a safe and reliable operating of its generation plants.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1901	PGE's Responses to OPUC Data Request Nos. 525, 618, 619, and 626
1902	Pelton-Round Butte Clean Water Act, Section 401
1903	Low Impact Hydro Institute certification for Pelton-Round Butte Project
1904	Port Westward Labor Cost Variance 2016 actuals vs 2017 budget vs 2018 forecast

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 619
Dated May 18, 2017

Request:

Please refer to the file produced in response to OPUC DR 525 "PSES -Compliance Specialist" which states "new generation plants and the ever-growing regulatory compliance landscape will require a new specialist position." Did the Carty 1 bid include labor costs associated with North American Electric Reliability Corporation and Western Electric Coordinating Council standard compliance? If no, why not? If yes, please provide the relevant sections of the bid.

Response:

The Carty 1 bid did not address costs associated with North American Electric Reliability and Western Electric Coordinating Council standard compliance. These services are provided by PGE's Power Supply Engineering Services (PSES) department and the bid did not include these services that are provided by the corporate PSES function, rather than plant-dedicated staff.

The "PSES-Compliance Specialist" is required in the PSES department for additional support to PGE's NERC and WECC compliance efforts due to the addition of Port Westward II, Tucannon River, and Carty generation plants between 2014 and 2016.

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 626
Dated May 18, 2017

Request:

Please refer to PGE/702.

a. Regarding Energy Market Settlement Analyst, please explain what work will be performed on the settlement files. Please provide a sample settlement file and explain how often PGE will receive these files.
b. Regarding the Energy Market Policy Analyst
  i. Please identify each policy and rule change implemented by the Western Energy Imbalance Market (EIM) in 2017.
  ii. Please explain why a full FTE is devoted to monitoring EIM policy and rule changes.
  iii. Does PGE devote a full FTE to monitoring any other single program policy changes? If yes, identify these programs and provide the associated position description.
c. Regarding the Independent Spent Fuel Storage Installation Technician, please explain how the DOE cost reimbursements are accounted for in the Company's 2018 revenue requirement.
d. Regarding the Port Westward 2 Generation Technician:
  i. Please identify each instance in 2016 where having 5 operating crews would have reduced costs or maintenance issues at Port Westward 2.
  ii. The file provided in response to OPUC DR 525 named "PW2 - Generation Technicians.pdf" indicates that 100 percent of the cost increase will be offset by reduced overtime and contractor expenses.

How are the reduced expenses associated with these FTEs incorporated into the 2018 revenue requirement?

e. **Regarding the Carty Generation Technician:**
   i. **Please explain why each gas plant needs its own planner scheduler.**
   ii. **Was the ongoing labor cost for a planner scheduler included in the Carty 1 bid? If yes, please provide the relevant sections of the bid.**
f. **Regarding the Power Supply Engineering Svcs Analyst:**
   i. **Please explain what the Reliability, Performance, and Monitoring Center is.**
   ii. **Please refer to the file produced in response to OPUC DR 525 named "PSES – Analyst.pdf". Please explain how the $350,000 in savings associated with this position are accounted for in the 2018 Revenue Requirement.**
g. **Regarding the Power Supply Engineering Svcs IT Analyst:**
   i. **Please identify the IT issues that occurred at Generation facilities in 2016 and provide the resolution time for each issue.**
   ii. **Please explain why a dedicated IT analyst will reduce the resolution time for Generation IT issues.**
   iii. **How are Generation IT issues currently addressed at PGE?**
   iv. **Will adding a dedicated generation IT analyst reduce the total labor hours spent on resolving generation IT issues? If no, why not?**
h. **Regarding the Power Supply Engineering Svcs Technical Writer Specialist:**
   i. **How does PGE currently develop and maintain generation procedures?**
   ii. **Has PGE's 2018 need to develop and maintain generation procedures changed relative to 2016? If yes, how?**
i. **Regarding the Generations Projects Project Manager:**
   i. **Please provide the number of active generation projects by year for 2013 through 2016.**
   ii. **How many active generation projects does PGE expect to have in 2018? How many of these projects relate to new wind or gas generation?**
j. **Regarding the Eastside Biological Services Technician, Environmental Communication:**
   i. **Does PGE have any other positions dedicated to single issue public relations? If yes identify such positions.**
   ii. **Please explain what costs associated with the Deschutes River Alliance lawsuit are included in the 2018 revenue requirement.**
   iii. **When does PGE anticipate that this lawsuit will be completed?**

> **iv. How has PGE determined that current communication and public relations regarding Deschutes fisheries has not been sufficient?**

Response:

a) Regarding the Energy Market Settlement Analyst:

As described in PGE Exhibit 300, the Energy Market Analyst(s) – Settlements will be responsible for market operations strategies and settlement analysis. In PGE's Response to OPUC Data Request No. 467, PGE reported on the expected hire dates for these positions.

The CAISO settlement process is complex and data intensive. As shown in the CAISO payments calendar, PGE will be receiving data from CAISO on a daily basis. The CAISO payments calendar is available at:

http://www.caiso.com/Documents/CaliforniaISOPaymentsCalendar2017.xls

Essential job responsibilities for the analyst roles will include:

- Validating Charge Codes related to CAISO by utilizing various software tools.
- Validating settlement allocation for non-participating resources and Merchant load.
- Disputing discrepancies with CAISO for assigned charge codes.
- Validating charge allocations received from various EIM entities within the EIM.
- Providing consulting with Day-Ahead and Real-Time Operation on bidding strategy. This can include post trade-day analytics and an evaluation of plant and bidding performance.

Due to the voluminous nature of the data, PGE is not providing an entire settlement file. A sample of settlement data is included as Attachment 626-A. Note that Attachment 626-A contains "test" data and is not actual settlement data. It is also a small sample of the data PGE will process on a daily basis when it is participating in the Western EIM.

b) Regarding the Energy Market Policy Analyst:

The description provided in PGE Exhibit 702 is not a comprehensive description of the position. As described in PGE Exhibit 300, this position will be responsible for market operations strategies and regulatory policy as it relates to the merchant role in the market. In PGE's Response to OPUC Data Request No. 467, PGE reported on the expected hire date for this position. This analyst role will maintain generation resource data required by the CAISO for market participation. The analyst will also follow changes to Western EIM market rules and evaluate the impact on PGE, financially and operationally. Additionally, in cooperation with settlements analysts, the market analyst will evaluate plant and bidding performance via post trade-day analytics.

> i. CAISO continually considers potential enhancements to the ISO market design, including the Western EIM (a part of the CAISO's real-time market). PGE is an

active participant in CAISO stakeholder processes. A catalog of active CAISO stakeholder initiatives is available at:

http://www.caiso.com/Documents/StakeholderInitiativeMilestones.xlsx

ii. See the description at the beginning of PGE's response. PGE's description in Exhibit 702 is not a comprehensive description of the position. Furthermore, OPUC Staff's interpretation (implied in its question) of a single program appears to be too narrow. EIM is not a program, it is a market. PGE's participation in policy formation and rule changes that may impact this market may occur in multiple venues (e.g., CAISO, FERC, and BPA). This position will assist in formulating PGE positions that seek to establish market rules that benefit PGE's customers.

iii. Please see PGE's response to part (ii) above.

c) Regarding the Trojan ISFSI Technician:

The Department of Energy (DOE) cost reimbursements related to Trojan have not been added in the 2018 test year revenue requirement calculations.

The concept of recording refunds in advance of receiving the funds from DOE falls under the gain contingency rules. The standard of recognition of a gain contingency is: "substantially all uncertainties about the timing and amount of gain contingencies should be resolved before being recognized"

PGE's position is that the Determination Letter, once executed, is sufficient evidence that substantially all uncertainties have been resolved and the gain contingency can be recognized. The Determination Letter is negotiated late in the process, usually in November during the last couple of years.

DOE refunds are recorded in the Schedule 143 (Spent fuel) regulatory liability. Please see PGE's response to ICNU Data Request No. 097 for DOE refunds recorded in Schedule 143.

d) Regarding the Port Westward Generation technician:

i. PGE objects to this request on the grounds that it calls for speculation.

ii. When comparing 2016 actuals to 2018 forecast there is no decrease in overtime and contractor labor expenses because of the significant O&M savings at Port Westward 1 (PW1) during the 2016 planned outage. The scope and timing of the outage changed primarily due to having to swap out the turbine rotor as it was damaged in 2015 and this was capital work rather than O&M. However, when comparing 2017 O&M budget to 2018 forecast there is a reduction of $250,000 in overtime and contractor expenses by having five operating crews at PW1 and

PW2. Attachment 626-B provides the calculation of the reduction in PW1 and PW2 overtime and contract labor from the 2017 budget to 2018 forecast.

e) Regarding the Carty Generation Technician:

   i. A planner scheduler is required at each generation plant to plan and schedule maintenance activities at the plant. Planning the maintenance work is a first critical step to ensure all maintenance jobs are completed in a safely manner. The planning also includes efficiency enhancements by ensuring that when maintenance jobs are stated, all parts and any specialty tooling is in site and staged to complete the work.

   ii. PGE's labor requirements forecast for the Carty Generating Station were based on the known staffing requirements for PGE's Port Westward plant. PGE included this forecast as part of its 2016 test year forecast in Docket No. UE 294, which was subsequently approved by Commission Order No. 14-059. This forecast included 22.7 FTEs at Carty, but two of the FTEs were transfers, resulting in effectively 21 incremental FTE increase in line with the assumptions serving as the basis in the O&M labor costs as part of the Carty RFP. Attachment 626-C provides PGE's response to OPUC Data Request No. 317 in Docket No. UE 294 with a detailed explanation regarding Carty FTEs in PGE's 2016 test year revenue requirement. The FTE in question has been working in the planner schedule function at Carty since August 2016.

f) Regarding the PSES Svcs Analyst:

   i. The Reliability, Performance, and Monitoring (RPM) center supports the Generation, Reliability and Maintenance (RME) program to improve PGE's maintenance practices that directly impact the operation of our generation resources. The RME program was discussed extensively in PGE's 2016 general rate case docketed under Docket No. UE 294, PGE Exhibit 700. Attachment 626-D provides the relevant pages from PGE Exhibit 700/UE 294 explaining the activities performed by the RPM center in support of the RME program.

   ii. The $350,000 cost reduction mentioned in the "PSES-Analyst.pdf" document was an estimate at the time the position request form was developed and was not at PGE share. In actuality, the PSES budget was reduced in 2017 by approximately $260,000 as result of bringing in-house the plant performance monitoring previously provided by General Electric (GE). Attachment 626-E provides the 2017 Accounting O&M Adjustment request reflecting the GE costs that were eliminated in the 2017 PSES budget and reflected in the calculation of the 2018 Revenue Requirement as a reduction to PSES Outside Services expenses.

g) Regarding the PSES IT Analyst:

PGE inadvertently included this FTE in two different departments. An FTE that performs the same functions as the PSES IT Analyst was added in PGE RC 778, IT Business Relationship Management (IT BRM) T&D and Generation support as a Technical Specialist IV. For more details about the IT BRM Technical Specialist IV please see PGE Exhibit 502, page 2, PGE's response to OPUC Data Request No. 484, Attachment 484-A, and PGE's response to OPUC Data Request No. 509.

i. Attachment 626-F identifies IT issues at generation facilities in 2016 and their resolution time.

ii. The IT BRM Technical Specialist IV would work to reduce the time it currently takes to resolve IT issues. For instance, Attachment 626-F shows IN10075604, a Carty Wi-Fi issue, with an extended resolution time. This position would help analyze the issue and follow up with the resources to make sure that the appropriate resources were diligently working on their issues and escalating within IT if that wasn't the case. They would also understand the business systems so that they would be the first line of support if there was a question or issue.

iii. Currently, IT issues are reported to the service desk, which dispatches resources based on priority and availability. There is no IT liaison to the business to ensure that their issues are being resolved so they will provide better support.

iv. This resource will reduce the time spent resolving generation issues by ensuring that a dedicated resource that understands generation systems and the IT issue resolution process is available.

h) Regarding the PGE Technical Writer Specialist:

i. Generation Fleet Procedures are being developed using US Department of Energy templates and best practices from PGE generation plants. Going forward, PGE anticipates the technical writer will add five to ten new Generation Fleet Procedures each year. Each procedure has a Lead who is responsible for coordinating the work to maintain the procedure after it has been issued. PGE recently developed 75 common Generation Fleet Procedures that are used by our generation plants.

ii. Yes, prior to 2016, each generation plant had a unique set of procedures. In 2016, PGE developed the common Generation Fleet Procedure and an associated SharePoint site and began rolling procedures out. The new set of Generation Fleet Procedures are housed and maintained in the SharePoint site. Each procedure is reviewed periodically, updated and procedure review comments are collected daily on a SharePoint log where they are addressed by subject matter experts. Procedure forms are updated several times a year to incorporate new work best practices.

i) Regarding the Generations Project Manager:

   i. The number of generation projects worked on by the Generation Projects group from 2013 through 2016 is:

      1. 2013: Six generation projects,
      2. 2014: Six generation projects,
      3. 2015: Ten generation projects,
      4. 2016: Ten generation projects.

   ii. The number of known generation projects that the Generation Projects group is expecting to work on in 2018 is seven. None of the seven projects are related to new wind or gas generation as the Integrated Resource Plan (IRP) is still in progress. Based on past experience of emergent work, the currently known projects for 2018 are likely a fraction of the number that will actually be worked. The Generation Projects group will continue to support the IRP, review qualifying facility applications, and evaluate technologies for pumped storage, geothermal, landfill gas, and other emerging technologies.

j) Regarding the Eastside Biological Services Technician, Environmental Communication:

   i. PGE has a centralized communications team in Portland that shares communications efforts on various issues such as safety, energy efficiency, customer programs, environmental issues, etc. Given the remote location, having a dedicated outreach resource allows us to be a better community partner in the region. Considering the outreach person will need to have technical expertise in natural resource issues is also a driver for this position.

   While the need for this position was brought to light by the DRA litigation, it is not wholly dedicated to this issue. This position also supports safety, energy, and habitat education as required by our Pelton-Round Butte Water Quality Certificate and Water Quality Management and Monitoring Plan FERC license:

      - Working with schools and business organizations this position arranges and conducts tours and provides education materials.
      - Coordinating and staffing public events and fairs with messages about safety and habitat

   ii. No costs associated with the DRA lawsuit were projected in the 2018 revenue requirements as planning for the litigation had not begun.

iii. It is difficult to determine litigation timelines due to its variable nature, but a reasonable estimate for federal court litigation is two years.

iv. PGE conducted a survey in January 2017 of 700 customers and Deschutes area residents, through DHM Research. The survey results indicated that PGE's outreach efforts were not sufficient. In addition, PGE received specific feedback from the Pelton Round Butte Fish Committee and signatory NGOs reflecting that current outreach efforts were not sufficient. As we monitored social channels, it was clear that additional work needed to be done to provide a counter-message to common misperceptions about the impact of PGE's operation on the river. Our opposition is very active and to continue to maintain our positioning, we need to be equally active, and this position plays a significant role in that effort.

UE 319

Attachment 626-A

Provided in Electronic Format only

Western EIM Settlement Sample

UE 319

Attachment 626-B

Provided in Electronic Format only

Port Westward 1 and Port Westward 2
Overtime and Contract Labor Reductions
2018 forecast vs 2017 budget

UE 319

Attachment 626-C

Provided in Electronic Format only

Docket No. UE 294
PGE's Response OPUC DR 317 – Carty FTE Count

UE 319

Attachment 626-D

Provided in Electronic Format only

UE 294 / PGE Exhibit 700
RPM Center Description

UE 319

Attachment 626-E

Provided in Electronic Format only

2017 O&M Adjustment
GE Smart Signal Cost Reductions

UE 319

Attachment 626-F

Provided in Electronic Format only

2016 IT Issues Resolution Times

April 2, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 317
Dated March 19, 2015

Request:

Referring to the above Staff DR 317, please provide a detailed explanation regarding any changes to number of FTE's, wages and salaries, overtime, and incentives from the base revenue requirement for Carty. Please include in the explanation references to UE 294 testimony and provide any work papers that support the Company's position.

Response:

PGE's labor requirement forecast for the Carty Generating Station (Carty) is based on the known staffing requirements for PGE's Port Westward plant. PGE chose the Port Westward plant as a basis for its labor requirement forecast, because Carty and Port Westward share the same plant equipment manufacturer (i.e., Mitsubishi Hitachi Power Systems America) and Port Westward has a similar plant layout and equipment configuration. As shown in PGE's response to OPUC Data Request No. 316 (See Attachment 316-A), we forecast 22.7 FTEs (including temporary labor). These FTEs are comprised of the following positions:

Employee Class	No. of Positions	Position Title
Union	8	Technician II
Union	8	Technician III
Exempt	1	Manager III, Plant Operations
Exempt	3	Project Manager
Exempt	1	Specialist V, Planner/Scheduler
Hourly	1	Assistant V
Hourly	0.7	Temporary Labor (Outage support)
Total	**22.7**	

Attachment 317-A provides the wages and salaries (excluding paid-time off) for the non-temporary positions listed above. Attachment 317-A is confidential and subject to Protective Order No. 15-036.

With respect to overtime, PGE assumes amounts equal to approximately 10 percent of annual hours for technician positions and approximately 6 percent of annual hours for the assistant position. Our assumptions estimate (1) the overtime hours needed for outage support (on an expected year basis) and (2) the overtime included in the normal shift for a technician. Over the course of a year, a normal shift for a technician includes overtime equal to approximately 4 percent of annual hours.

With respect to incentives, PGE forecasts incentive costs for employees at Carty based -on the incentive plan structure methodology implemented for the bargaining and non-bargaining employees at the Coyote Springs and Port Westward plants. As described on page 17 of PGE Exhibit 500, PGE has found the incentive plans at Port Westward and Coyote Springs to be effective in motivating employees to pursue efficiencies, enhance their professional development, and maintain a high level of operations.

UE 294

Attachment 317-A

Confidential and Subject to Protective Order No. 15-036

Provided in Electronic Format only

Position Salaries Excluding PTO

(SHARP). Biglow Canyon Wind Farm's (Biglow) SHARP status is currently pending and is expected to be awarded in early 2015. In 2011, Coyote Springs achieved VPP Merit status, the first level of participation within OSHA VPP. Coyote Springs is positioned to achieve Star status during 2016.

Q. What safety initiatives does PGE have planned for 2016 and beyond?

A. Using our mySafety software platform, PGE's Generation Safety team will continue to integrate software-based tools into our generation business processes. Our emphasis in 2016 will be on incident reporting follow-up, job safety analysis, behavior-based safety observations, and leading indicators. All generation managers and supervisors are expected to take a safety leadership training course over a two-year period, concluding in 2016. Additionally, PGE is targeting OSHA VPP Merit or Star status at each generation facility by 2018.

2. Reliability

Q. How is PGE managing its O&M practices with regard to reliability and availability?

A. Our Generation Reliability and Maintenance Excellence (RME) program improves our maintenance practices that directly impact the operation of our generation resources. Additionally, as part of the Dynamic Dispatch Program (DDP), the Power Supply Engineering Services (PSES) department engaged in generation plant cycling studies to better define the capabilities and operating parameters of some of PGE's generation resources.

Q. Please summarize the RME effort.

A. RME is PGE's comprehensive equipment management program that supports plant safety and availability. PGE uses RME to operate and maintain plant equipment to achieve the lowest overall life cycle cost. While RME is an ongoing, continuously evolving program for PGE, we aim to achieve a sustained long-term top quartile availability factor at each plant with optimized maintenance costs. To achieve our generation operations goals, we are implementing metrics, standards, and tools that include:

- Modeling plants with Reliability Block Diagramming software;
- Ranking assets by importance to inform the management plan for assets;
- Continuously optimizing maintenance through Reliability Centered Maintenance evaluations;
- Using condition-based monitoring tools and programs to reduce the amount and impact of corrective maintenance;
- Training and adhering to fleet-wide work standards; and
- Targeting practices to include approximately 80 percent proactive maintenance and 20 percent corrective maintenance.

Q. When does PGE anticipate achieving these expected results?

A. The current goal for achieving these expected results is year-end 2017. However, RME is a sustained strategy and will be an ongoing, evolving program that continues to improve PGE's maintenance practices.

Q. How do these efforts benefit customers?

A. RME produces asset-related and personnel-related benefits for PGE and our customers. The primary asset-related benefits are:

- Increased plant availability and reliability;
- Optimization of maintenance practices and equipment replacement; and,
- Installation of new equipment with the lowest lifecycle cost.

The asset-related benefits result in lower NVPC for our customers and higher levels of reliability to serve customer load.

The primary personnel-related benefits are:

- Improved safety;
- Workforce efficiency and effectiveness; and,
- Knowledge transfer.

The personnel-related benefits result in better use of our existing staff, more efficient maintenance procedures, more effective information sharing, and allow new plant staff to more quickly learn plant maintenance procedures. All of these benefits contribute to more efficient and effective operation and maintenance of our generation assets.

Q. Does PGE plan to expand on any of these efforts in 2016?

A. Yes. PGE plans to create a centralized onsite monitoring and diagnostic (M&D) center beginning in 2016. The objective of the M&D center is to create a centralized and integrated fleet-wide monitoring center that will improve PGE's ability to detect and correct equipment and performance problems at our plants. Additionally, the data available from the M&D center will allow greater visibility of plant asset conditions, which directly support our RME program's focus on maintenance efforts to reduce the risk of equipment failure and to reduce the economic impact of any plant outage.

Q. Has PGE benchmarked peer utilities' monitoring and maintenance programs?

A. Yes. PGE's reliability centered maintenance, technician training, employee performance, and safety programs were in-line with or slightly more mature than peer utilities. However, peer utilities had more developed fleet-wide monitoring programs than PGE.

Q. How does PGE currently monitor its assets?

A. PGE uses a third-party vendor to perform fleet-wide monitoring, which has proven effective at reducing operation costs through improved detection of equipment problems. However, the current monitoring program has limitations regarding the depth of monitoring and the lack of real-time thermal performance analysis. Additionally, the outside vendor is not fully integrated into PGE's culture and process, decreasing our effectiveness at correcting equipment problems detected through monitoring.

Q. How will the improved monitoring from the M&D center benefit customers?

A. The M&D center will align maintenance to the condition of plant assets, increase early detection of component failures, standardize monitoring across PGE's fleet, and reduce labor used for periodic inspections. The M&D center will directly benefit customers through improved generation reliability and availability, which will allow PGE to maximize economic dispatch of our generation assets and reduce replacement power costs due to unexpected outages. Improved fleet monitoring also creates alignment between the monitoring program and condition-based maintenance, which result in reduced labor used for periodic inspections and maintenance.

Q. Please summarize the plant cost of cycling studies.

A. We recently completed cost of cycling studies for PGE's thermal generation fleet and the Pelton and Round Butte (PRB) hydroelectric plants. The purpose of these studies is to develop and analyze the cost associated with cycling each unit, based on historical operating and cost information. With these studies, we are able to estimate future costs associated with increased cycling due to market and regulatory changes, such as 15-minute scheduling.

To complete these studies, PGE contracted with a third-party firm that has over two decades of experience and has completed over 400 cycling cost analyses.

Q. What is plant cycling?

A. Cycling is the frequent movement of output (i.e., increasing or decreasing of generation) produced by a plant. This includes on and off cycling (i.e., plant start-ups and shut downs) and load following. For traditionally base load thermal plants, load following is movement greater than 20 to 50 percent of the unit's gross dependable capacity.

Q. How does PGE plan to use the information from the plant cost of cycling studies?

A. The studies will provide valuable operating information to our Power Operations group, PSES, and plant operators. PGE plans to use the results from the cost of cycling studies as a wear and tear component cost for economic dispatch of the plants, particularly in the Real Time Dispatch Tool (RTDT) being developed for portfolio optimization under the DDP. Additionally, the studies provide information regarding specific plant operating constraints that can be incorporated in the MONET model. PGE Exhibit 400 discusses updates to the ancillary service assumptions in MONET based on the results of the cost of cycling studies.

B. Plant O&M

Q. What are the changes in PGE's plant O&M between 2014 and 2016?

A. Table 1 below summarizes the changes in total Plant O&M expenses. These amounts include adjustments for emissions control chemical costs and the various major maintenance accruals.

Stefan Cristea

2017 Test Year
O&M Adjustment Request

Department: 551

Manager: Brian Clark

Dept. Title: Power Supply Engineering Services

Corporate Planning Analyst: Spenser Williams (Generation)

Accounting:

Dept:	OU:	Account:	CE:	AWO:	Incremental Dollars:	Hours:	Line Description:
551	18100	5570003	2300	7000001135	="-163,125	0	Miscellaneous Software Maintenance
551	18100	5570003	2300	7000000682	="-16,200	0	R&ME Software Maintenance
551	14100	5460001	2200	7000001976	="-42,485	0	Smart Signal - Beaver
551	16100	5460001	2200	7000001978	="-35,591	0	Smart Signal - Coyote Springs
551	16400	5460001	2200	7000001977	="-54,250	0	Smart Signal - Port Westward
551	17200	5460001	2200	3000000014	="-45,557	0	Smart Signal - Biglow Canyon
551	17400	5460001	2200	3000000014	="-25,601	0	Smart Signal - Tucannon River
551	92100	5060001	2200	7000001975	="-58,724	0	Smart Signal - Boardman

1. Provide a short description for each of the O&M adjustments.

CE 2300 adjustments transfer software licensing expenses to IT Department 737. CE 2200 adjustments reduce the Smart Signal consulting fees to partially offset the addition of FTEs to support the Performance and Reliability Center.

2. Why is this adjustment needed; what has changed in your department that drives this need?

PGE IT has assumed responsibility for software maintenance enterprise wide. Development of the Performance and Reliability Center eliminates the need to continue use of outside services to perform this monitoring.

3. If you are requesting an increase, are there any cost reductions to offset the O&M increase?

N/A

4. Describe other options considered

No other significant reductions or additions have been identified at this time.

5. Other Comments

For Corporate Planning Use Only:

Officer Signature: **Date:**

July 27, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 673
Dated July 20 2017

Request:

Please refer to PGE/1900 Jenkins – Rodehorst/4.

a. **Has Staff recommended that PGE not fill the Trojan positions? If yes, please provide reference to this recommendation.**
b. **Does PGE agree with Staff's claim at Staff/700 Kaufman/28 that PGE expects to be reimbursed for the costs associated with these FTE? If no, why not?**
c. **What is the dollar amount that PGE expects to be reimbursed for these FTE?**
d. **Please refer to PGE's response to OPUC DR 626 part c. Please explain why accounting treatment of gain contingencies precludes recognition of these revenues in PGE's general rate case revenue requirement.**

Response:

In summary, PGE collects $3.5 million annually for Trojan nuclear decommissioning. This amount covers all expected annual nuclear decommissioning activities, such as O&M, and includes Trojan-related FTE costs. The $3.5 million is a fixed amount and is included in PGE's 2018 revenue requirement calculations.[1] Removing or adding Trojan FTEs will not cause a change to the $3.5 million and consequently, would not impact PGE's 2018 revenue requirement. Additionally, PGE's share of the costs associated with the Trojan Independent Spent Fuel Storage Installation (ISFSI) Technician FTEs is expected to be reimbursed to PGE customers through Supplemental Schedule 143-Spent Fuel Adjustment via the settlement claim with the Department of Energy (DOE).

a. Yes. In Staff Exhibit 700, at page 28, lines 17-19, Staff "recommends that the FTE be excluded from rates" because "PGE has not accounted for this reimbursement in this rate case."

[1] See PGE Exhibit 200, Work Papers_200_Non-Conf, Exhibit Support 2018, tab "Ex 204 Amort", cell I11.

PGE believes this is a recommendation that PGE not fill the Trojan ISFSI Technician positions or risk disallowing these FTEs from rates. As noted in the summary response above, although not included in the 2018 revenue requirement, DOE reimbursements related to Trojan nuclear decommissioning are included in this rate case and refunded to customers through Supplemental Schedule 143-Spent Fuel Adjustment. The removal or addition of Trojan-related FTEs does not impact PGE's revenue requirement.

b. Yes. Please see PGE's summary response above.

c. PGE expects to be reimbursed with approximately $0.26 million for the incremental Trojan FTEs (i.e., 2018 forecasted FTEs compared to 2016 actual FTEs).

d. The accounting treatment of gain contingencies does not preclude PGE from including the DOE reimbursements in its test year revenue requirement. However, as stated in the summary response above, the DOE reimbursements are refunded to customers through Supplemental Schedule 143-Spent Fuel Adjustment, including approximately $2.0 million in 2018. In addition, there is a timing issue with the refunds as they would occur in a different accounting period than the costs. Accordingly, PGE would not include the reimbursements in its 2018 base revenue requirement calculation.

Exhibit 706C

Protected Information Subject to Protective Order 18-047

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Transmission and Distribution O&M

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Bill Nicholson. I am Senior Vice President of Customer Service and Transmission and Distribution.

My name is Larry Bekkedahl. I am Vice President of Transmission and Distribution.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain PGE's Transmission and Distribution (T&D) activities and costs for the 2019 test year. Our activities will allow us to maintain and enhance our T&D system to meet customer growth and reduce system reliability risks. Additionally, we discuss our request to modify the current storm accrual to allow for full recovery of prudently incurred storm restoration costs, and for the Public Utility Commission of Oregon (OPUC or Commission) to approve our 2017 storm deferral application filed in Docket No. UM 1817.

Q. What are T&D's primary goals?

A. Our primary goals are to:

- Provide safe, affordable, secure, and reliable energy delivery services to our customers;
- Cultivate a culture that improves employee and public safety;
- Enhance efficiency and increase customer value by deploying new techniques, technologies, industry best practices, and process improvements; and
- Ensure compliance with applicable regulations, including those addressing T&D grid reliability and operations.

Q. How is the remainder of your testimony organized?

A. Our testimony has five additional sections. In Section II, we discuss operation and maintenance (O&M) costs in the 2019 test year. In Section III, we discuss capital investments that are anticipated to close by the end of this year as well as the labor resources supporting those projects. In Section IV, we discuss Level III storm costs in 2017 and our storm restoration efforts for the benefit of customers. We also discuss our proposal to allow the storm accrual to have a negative balance, as well as positive balance, to allow for the recovery of prudently incurred costs associated with storm restoration and to normalize storm restoration costs in PGE's customer prices. We then summarize our requests discussed in this testimony in Section V and present our qualifications in Section VI.

II. Transmission and Distribution Operations

Q. What are your O&M costs for the 2019 test year?

A. Table 1 presents our expected O&M costs for 2019. We forecast T&D O&M costs totaling $110.7 million during the period, which represents a $1.6 million decrease from 2017 actuals. Including Information Technology (IT) raises the total costs to $152.0 million.

Table 1
Summary of T&D O&M Expenses (Millions)

	2017 Actuals	2019 Test Year	Variance 2017 - 2019	Average % Change
T&D Labor	$51.7	$55.4	$3.7	3.5%
T&D Non-Labor	$60.5	$55.3	($5.3)	(4.4%)
T&D O&M (excluding IT)	**$112.3**	**$110.7**	**($1.6)**	**(0.7%)**
T&D IT	$30.2	$41.3	$11.1	16.9%
Total T&D O&M*	**$142.5**	**$152.0**	**$9.5**	**3.3%**

** Numbers may not sum due to rounding.*

Q. Are there offsetting cost savings reflected in the 2019 test year for T&D O&M costs?

A. Yes. T&D is reducing its O&M costs by approximately $1.1 million while continuing to enhance our system to meet customer growth and reduce system reliability risks.

Q. What do the IT costs represent?

A. IT costs represent costs that are directly assigned or allocated to T&D as they relate to the development, operations, and maintenance of our computer, cyber, and communication systems.

Q. Are allocated IT costs the primary driver of the increase in IT costs from 2017 to the 2019 test year?

A. Yes. Approximately $10.0 million of the increase in IT costs is due to work in the areas of cybersecurity, voice, data, network, communications, business recovery, data center, and office systems that apply broadly to all PGE activities and departments. Since these costs relate to all areas of PGE's operations, they appear as part of each area's O&M costs.

Q. Please explain the forecasted increase in IT costs.

A. In summary, the increase in IT costs results from the following drivers:

- An increased risk related to cybersecurity attacks, resulting in the need to accelerate the implementation timeline for our Integrated Security Program and improve network resiliency to ensure the security of our information and control systems that operate the grid and protect them from cyber vulnerabilities;
- Increased software/hardware costs for new and/or upgraded systems to improve cyberthreat monitoring and system effectiveness; and
- Labor loadings on allocated IT costs.

Because IT costs are charged to all operating areas of the company, they are discussed in detail in PGE Exhibit 600.

Q. Table 1 shows that T&D non-labor costs are decreasing while T&D labor costs are increasing. Why are T&D labor costs increasing?

A. T&D labor costs are increasing primarily due to inflation. We applied an approximate 3.0% average escalation rate for all labor to arrive at the 2019 test year forecast. PGE Exhibit 400 provides additional details on wage escalation rates used in this general rate case.

Q. Are new program costs included in the 2019 test year as a result of PGE's 2018 general rate case filed in Docket No. UE 319?

A. Yes. One new program is PGE's Low Clearance Correction Program, as stipulated in Docket No. UE 319 (UE 319) and adopted by Commission Order No. 17-511 (Order 17-511). PGE began program implementation at the start of 2018 to correct (i.e., bring up to

National Electric Safety Code (NESC) standards) low vertical clearance conditions involving customer-side equipment, which are identified during PGE's annual Facility Inspection and Treatment to the NESC (FITNES) Program. Per Order 17-511, PGE will implement a ten-year inspection cycle and two-year correction cycle for service connections with points of attachment (POA) below eight feet, and between eight and ten feet. PGE will also provide an annual report with the information identified in the Commission's Order.[1]

Q. What costs are included in the 2019 test year to execute this program?

A. PGE included approximately $1.6 million in rates to continue this program in the 2019 test year. This is consistent with the amount authorized in our 2018 test year case, adjusted for inflation.

[1] Order 17-511, pages 7-8, provide additional details specific to the Low Clearance Correction Program.

III. Capital Investments

Q. Why is PGE increasing its capital investments in the T&D system?

A. PGE is increasing its capital investments in the T&D system to:

1. Support a significant increase in the number of new customer connections;
2. Upgrade equipment that is nearing the end of its life; and
3. Rebuild portions of the T&D system to improve reliability.

These investments will address a continuing growth of customer-driven work, an aging asset fleet, and expanding regulatory and compliance demands along with safety and environmental concerns.

Q. What are the main types of capital investments expected to close in 2018?

A. The capital investments expected to close in 2018 fall primarily into two categories:

- Customer-driven capital work, which includes system expansion activities related to economic and localized load growth;[2] and
- Strategic capital improvements for customer risk reduction in the T&D system (e.g., substation upgrades, underground cable, pole, and polychlorinated biphenyl (PCB) transformer replacements).

A. Customer-Driven Capital Work

Q. Please describe customer-driven capital work.

A. Customer-driven capital work refers to capital investments that are either a direct result of customer requests (e.g., new customer connections, road widenings, and supporting infrastructure expansions) or are needed as a result of our growing customer base.

[2] While we are experiencing load growth in some areas of our service territory, overall forecasted loads for PGE's residential and commercial sectors are expected to decrease in 2019. PGE Exhibit 1100 provides additional details on PGE's load forecast.

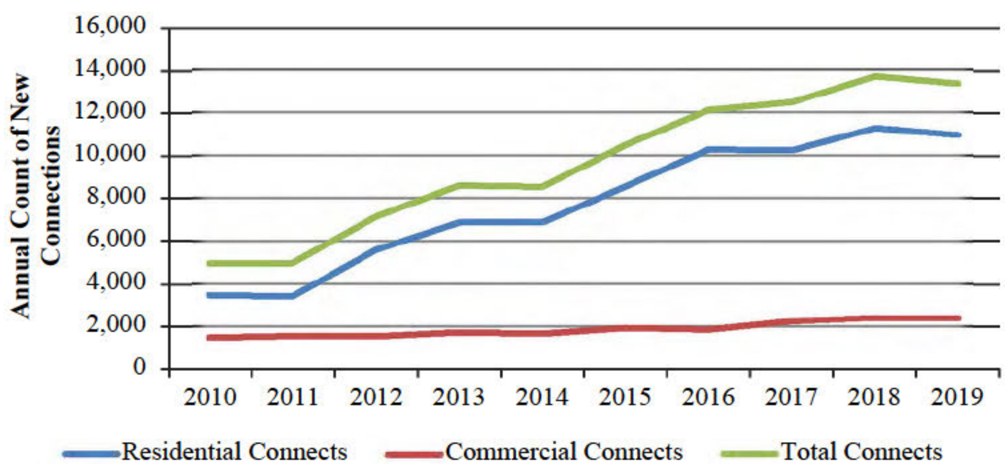
Q. Can PGE limit the number of new customers that it connects?

A. No. Oregon Administrative Rule (OAR) 860-021-0045 states, "For the connection of its distribution system to the customer's premises, an electric company shall, with the exceptions provided under its extension rules, furnish service connections to the customer's service entrance."[3]

Q. Please describe the growth of new customer connections.

A. As seen below in Figure 1, the annual number of new customer connections has increased by approximately 152% from 2010 to 2017.[4] As discussed in PGE Exhibit 100, economic activity has been driving in-migration, growing customer count, and increasing customer connects and demands on our system.[5] Growth in customer connections is particularly strong in Multnomah, Washington, and Clackamas counties.

Figure 1
New Customer Connection Trend



[3] For additional details on PGE's electric service requirements, see: https://www.portlandgeneral.com/construction/electric-service-requirements.
[4] The annual count of new connections for 2017 reflects actuals through November plus a December forecast. The annual count of new connections for 2018 and 2019 is also forecasted.
[5] PGE Exhibit 100, page 7.

Q. What is PGE's forecast for new customer connections?

A. PGE forecasts continued growth in new customer connections of 7.0% from 2017 to 2019, to approximately 13,350 new annual connections. PGE Exhibit 1100 provides further details regarding customer growth.

Q. What significant customer-driven capital work will be completed by year-end 2018?

A. There are two significant projects. First, the Marquam Substation and its associated infrastructure are expected to be energized in 2018 (approximately $60.2 million). This infrastructure is necessary to support load growth in the South Waterfront District and to improve network reliability for the downtown Portland area by providing N-1 redundancy[6] to the distribution system. Second, preliminary infrastructure for Rock Creek Substation will also be in-service to support load growth in the greater Hillsboro area (approximately $3.2 million).

Additional customer driven-work that will be completed includes:

1. Installing service lines, poles, meters, and transformers for new residential and commercial customers; and
2. Upgrading infrastructure for expanding industries and commercial customers.

B. Strategic Capital Improvements to Reduce Customer Risks

Q. Please describe PGE's strategic capital investments that will be completed by year-end 2018 to reduce customer risks in the T&D system.

A. PGE is upgrading its T&D network to replace infrastructure operating beyond its life and increase system reliability through three projects:

1. T&D Substation Reliability Upgrades (approximately $29.3 million);

[6] N-1 redundancy is a form of resilience that ensures system availability in the event of system failure.

2. PCB Transformer Replacements (approximately $15.6 million); and
3. Underground Cable Replacement Program (approximately $10.3 millon).

These projects will reduce customer risks in the T&D system related to aging and environmentally hazardous substation assets, aging cable in the distribution system, and external causes of service failures in the distribution system (e.g., weather and vegetation events). The benefits of these projects include service restoration cost avoidance, increased network reliability, and customer satisfaction improvements.

Q. Does T&D face challenges when executing capital investment plans?

A. Yes. There are several challenges that PGE's T&D organization continues to face when planning and executing capital investment plans, including more complex permitting processes, tightening construction restrictions, and traffic congestion.

1. Permitting Processes and Construction Restrictions – Over the last few years, the permitting processes have become increasingly complex. There is no uniform process; rather, the process is governed by the local government where the development is occurring. Customer work that previously did not require a permit now requires one. In addition, restrictions have been imposed on when and how our work is conducted, which increase costs and create additional complexity in scheduling. For example, certain city requirements constrain the time of day when PGE may perform any work, mandating that the work be performed at night or restricted to certain days (due to traffic, noise, and/or other considerations).
2. Traffic Congestion – Traffic congestion has affected PGE's crews' ability to access work sites quickly. A recent report in 2016 by the Oregon Department of

Transportation found that "[d]ata for the [Portland] region's six freeways[7] show increasing congestion, decreased travel speeds, greater delays, and unreliable trip times." The report also noted that traffic congestion in the Portland region is no longer only a weekday peak hour problem, and that it can occur at any hour of the day, including weekends and holidays.[8] Similarly, the most recent traffic congestion report by INRIX, a global transportation analytics company, ranked Portland's commute as the 12th worst in the nation. This congestion adds time to PGE crews' completion of work.[9]

C. Labor Resources

Q. If PGE will need additional labor resources to execute this capital work, how will PGE acquire the necessary labor resources?

A. PGE uses a balanced approach of internal labor and contractors to execute capital work. As discussed in UE 319, PGE is hiring additional employees along with contract labor to address the higher and on-going levels of T&D investments.

Q. Does T&D continue to face hiring challenges?

A. Yes. T&D has encountered challenges to fill union jobs and specialized positions in the current labor market. The time requirements involved to recruit, hire, and retain in-demand professionals has increased due to the tight labor market both within Oregon and nationally. Additionally, for positions such as line workers, PGE is more frequently recruiting individuals who must relocate to Oregon due to the scarcity of available and qualified

[7] The report studied data from the start of 2013 to the end of 2015 on Interstate 5, Interstate 84, Interstate 205, Interstate 405, Oregon 217, and U.S. 26.
[8] See http://www.oregon.gov/odot/regions/documents/region1/2016_tpr_finalreport.pdf for additional information.
[9] See http://inrix.com/scorecard/ for additional information.

candidates. PGE Exhibit 400[10] provides additional details regarding recruiting and hiring challenges for specialized positions.

Q. How does T&D accomplish its capital work given the hiring challenges?

A. T&D accomplishes its capital work in these circumstances by hiring contractors to complete the work that must be finished on a timely basis. Contractors are used to supplement PGE labor to address a number of labor needs. These needs include: short-term assignments, specialized knowledge that may not be available in our market or at our wage levels, and for staffing up on projects that have a finite time frame and a need for a short-term influx of personnel.

Q. How much do you project T&D full time employees (FTEs) will increase from 2017 to 2019?

A. We project that T&D FTEs will increase by approximately 109 from 2017 to 2019. This increase, however, is expected to occur between 2017 and 2018 as we complete the hiring that we described in UE 319 for capital purposes. No additional PGE FTEs are expected to be hired from 2018 to 2019. In summary, the entirety of PGE's FTEs increase for T&D operations from 2017 to 2018 reflects PGE completing the hiring for the capital work we described in UE 319, PGE Exhibit 800, and restated above. In addition, PGE provided specific detail for these incremental FTEs in UE 319 and include that here as PGE Exhibits 802 and 803.

Q. Do these FTEs impact O&M costs?

A. Yes. However, as noted in Section II above, T&D O&M costs are increasing primarily at the rate of escalation, which reinforces that the currently projected FTE increase is focused

[10] PGE Exhibit 400, page 6.

on capital work. To the extent that PGE experiences any delay in filling these positions, we will substitute contract labor to complete the planned capital work. In summary, to complete the necessary capital work that we describe above in subsections A and B, FTEs and contractors represent interchangeable labor costs.

IV. Major Storms

Q. Did PGE experience any major storms in 2017?

A. Yes. In 2017, PGE experienced four Level III storms[11] (and experienced a fifth storm that nearly qualified as Level III), resulting in approximately $11.4 million in Level III storm damage and restoration costs, far exceeding PGE's storm accrual of $2.0 million.

Q. What are the criteria for a Level III storm?

A. Pursuant to Commission Order No. 10-478 (Order 10-478) from Docket No. UE 215 and the intent of the settlement regarding storm damage, one of the following criteria must be met for a storm to be considered Level III:

1. Impacts at least 50,000 customers; or
2. Qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion;[12] or
3. Several substations and feeders are out of service.

Q. Please briefly describe PGE's storm restoration efforts.

A. PGE takes an 'all-hands-on deck' approach to storm restoration efforts. During a severe weather event, all available field workers and on-site line contractors are dispatched to identify and repair the source of outages. For instance, over 1,000 people were deployed during our April 2017 wind storm to restore power for approximately 185,000 customers who were out of power at the peak. We also respond to '911' calls of downed power lines and de-energize these lines to mitigate unsafe conditions. Depending on the severity of the

[11] We use the terms "major storm," "major event," and "Level III storm" interchangeably in this testimony.
[12] An IEEE Major Event Day exclusion is a day in which our daily System Average Interruption Duration Index (SAIDI) exceeds a threshold value. In 2017, the T_{med} was 4.84 minutes. If our accrued daily SAIDI minutes exceed the threshold, that day is considered a major event day (MED) and is analyzed separately from events occurring on days that are not MEDs for PGE's annual reliability reports, pursuant to OAR 860-023-0151.

event and the number of outages across our service territory, we may also make a request for contractors from outside our service territory, as well as mutual aid from other utilities, to assist us with storm restoration efforts.

Q. What costs are incurred in order to restore power quickly for customers?

A. As described above, we primarily incur labor costs to dispatch crews to identify and mitigate outages. We incur significant overtime costs associated with PGE crews, as well as an increase in outside services support for contract line crews and mutual aid from other utilities depending on the severity of the storm. Severe traffic gridlock can also affect the crews' ability to access sites quickly, which increases the amount of hours worked by crews. While we actively manage labor costs associated with power restoration, these costs are, to a significant extent, due to events that are beyond PGE's control.

Q. Doesn't PGE have a major storm deferral account to help with the cost of major storms?

A. Yes. Per Order 10-478, PGE collected $2.0 million annually to pay for service restoration following Level III storms. The annual accrual is based on a rolling ten-year average of Level III storm costs, adjusted to reflect present value costs. PGE currently collects $2.6 million for use against future Level III storms based on the rolling ten-year average of Level III storm costs from 2007-2016.[13]

Q. Does PGE propose to modify the storm accrual?

A. Yes. PGE proposes to continue accruing for costs attributed to Level III storms annually, but if storm costs exceed the amount collected from customers, the balance of accrued funds would become negative, and be offset in subsequent years when damage from Level III

[13] Order 17-511 in UE 319 increased the annual collection amount for Level III storm costs from $2.0 to $2.6 million starting from January 2018.

storms is less than the annual accrual amount. Under this treatment, PGE could recover incurred storm costs while occasionally carrying a negative balance in the storm account. The proposed major storm accrual allows customers to pay for appropriate storm costs, as determined by a prudence review and/or audit, and smooths the impact of storm costs on customer prices by normalizing those costs over time.

Q. Do other utilities receive balancing accounts from their regulators?

A. Yes. Many utilities have balancing accounts in varying forms. For example, Alabama Power,[14] Entergy Arkansas,[15] and Pacific Gas and Electric Company (PG&E)[16] are examples of investor-owned utilities that receive this type of accounting treatment from their regulators to provide them with the opportunity to recover storm costs.

Q. Is PGE proposing to update its major storm accrual based on the current 10-year rolling average?

A. Yes. Per Order 10-478, which ordered use of the ten-year rolling average for Level III storm costs, PGE proposes to increase the storm accrual rate to $3.8 million annually, as detailed in PGE Exhibit 801, to reflect an additional year of actual Level III storm costs.

[14] By Order dated December 6, 2005 in Docket No. U-3556, the Alabama Commision approved Alabama Power's request to record O&M expenses associated with natural disasters in their Natural Disaster Reserve (established in 1994), even when expenses cause a negative balance in the account.

[15] Order No. 3 in Docket No. 09-031-U, pursuant to Arkansas statute, approved Entergy Arkansas' request to establish a storm reserve account and allow a debit balance. Entergy Arkansas must file quarterly reports identifying instances in which they recorded costs in the storm reserve for the Arkansas Commision to audit, analyze, examine, and adjust these costs for reasonableness and prudency.

[16] Decision 14-08-032 in Docket No. 14-08-031 approved PG&E's request for a Major Emergency Balancing Account (MEBA). The MEBA is a two-way balancing account that records and recovers actual expenses and capital revenue requirements resulting from catastrophic events that are not declared a state of emergency.

Q. What costs will be included in the major storm accrual?

A. Only a Level III event causing damage to PGE's T&D system (and which receives a PGE accounting work order number) will be included. PGE will continue to use the criteria stated above to determine a Level III event.

Q. Are these storm costs appropriate to recover from customers?

A. Yes. PGE incurs significant incremental costs during Level III events for customers' benefit because we recognize the importance of the service we provide in promoting public safety and welfare. As discussed in PGE Exhibit 100, pages 5-6, the reliability expectations of our customers are increasing and we must meet these expectations by reasonably using all available resources to restore customers' power as soon as possible. However, during a Level III event, straight-time labor and contract line crews are diverted to the storm response, leaving less available for other O&M and capital work. These costs are incurred to ensure public safety and welfare, and to meet customers' increasing reliability expectations, and should be recoverable.

Q. Why is it important for PGE to receive Commission approval to update the major storm accrual?

A. The current storm mechanism limits PGE's ability to recover storm costs that enable us to provide safe and reliable power for our customers during severe weather events. Commission approval for the major storm accrual would provide PGE with the opportunity to recover prudently incurred storm costs, which will continue to increase as more frequent and severe storms impact our service territory in the future. Thus, Commission support for the major storm accrual is important to manage customer price impact by normalizing the sporadic nature of storm costs for the purpose of establishing customer prices.

Q. Does PGE have other requests with respect to recovering storm-related costs?

A. Yes. PGE filed for a deferral on January 11, 2017 for storm-related restoration costs not covered by the current major storm accrual mechanism. Our deferral filing was docketed as UM 1817. To the extent that UM 1817 is unresolved, we request the Commission approve our deferral and apply these costs to our proposed balancing account.

V. Conclusion

Q. Please summarize your request for T&D in this testimony.

A. We request that the Commission approve PGE's forecast of approximately $152.0 million (including IT) in T&D O&M costs in the 2019 test year, representing a $9.5 million, or 3.3% increase, compared to 2017 actuals. We also request that the Commission approve an increase of $1.2 million to accrue $3.8 million in rates annually for Level III storm restoration costs, consistent with prior approved methodology for calculating this accrual. In addition, we request that the Commission approve PGE's proposal to allow the storm accrual balance to have negative as well as positive balances in order to allow PGE to recover prudently incurred costs associated with quickly restoring power for our customers and to normalize storm restoration costs in customer prices. Finally, we request that the Commission approve our deferral of expenses related to 2017 storm restoration costs and apply the costs to our proposed balancing account.

VI. Qualifications

Q. Mr. Nicholson, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from Oregon State University. I completed the Harvard University Program on Negotiation and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon and I belong to the National Society of Professional Engineers. My employment with PGE started in 1980 as an engineer at the Trojan Plant and I have served in a variety of capacities in Distribution Operations, Generation Engineering and Resource Development. In May 2007, I became Vice President of Customers & Economic Development and in August of 2009, I was appointed Vice President of Distribution. In April of 2011, I assumed my current role as Senior Vice President of Customer Service and Delivery, Transmission and Distribution.

Q. Mr. Bekkedahl, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering from Montana State University. I serve on the Electric Power Research Institute's Power Delivery executive committee, as a U.S. board member for the International Council on Large Electric Systems (CIGRE), and on the member's advisory committee for Peak Reliability, the Reliability Coordinator for the Western Grid. My employment with PGE started in August 2014 as Vice President of Transmission and Distribution. Prior to that, I served as Senior Vice President for Transmission Services at the Bonneville Power Administration (BPA), and have held other leadership and management positions at BPA, Clark Public Utilities, PacifiCorp and Montana Power Company. I also have international utility experience gained by participating in a six month exchange program with Hokuriku Electric Power

Company in Toyama, Japan, developing hydro projects in the Philippines, and participating in United States Agency for International Development (USAID) exchange projects in Bangladesh, the Republic of Georgia, and the Philippines.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801	Major Storm 10-Year Analysis
802	UE 319, PGE Exhibit 800, Pages 18-19
803	UE 319, PGE Exhibit 802, Incremental FTE Explanations

2008 - 2017 Actual Level III Storm Damage Losses

CPI	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2008	$ 5,936,058									
2009	-0.32%	$ 2,106,514								
2010	1.64%	1.64%	$ -							
2011	3.14%	3.14%	3.14%	$ -						
2012	2.08%	2.08%	2.08%	2.08%	$ -					
2013	1.47%	1.47%	1.47%	1.47%	1.47%	$ -				
2014	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	$ 5,623,875			
2015	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	$ 5,161,601		
2016	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	$ 4,504,081	
2017	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	$ 11,351,424
2018	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%
2019	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%
2019 $	$ 7,116,504	$ 2,533,532	$ -	$ -	$ -	$ -	$ 6,131,009	$ 5,620,389	$ 4,842,643	$ 11,902,883

Ten Year Total Level III Storm Damage Losses	$ 38,146,960
Ten Year Avg Level III Storm Damage Losses	$ 3,814,696
Average Level III Storm Damage Losses	$ 6,357,827

Year	Level III Storm Actuals	CPI
2008	$ 5,936,058	3.81%
2009	$ 2,106,514	-0.32%
2010	$ -	1.64%
2011	$ -	3.14%
2012	$ -	2.08%
2013	$ -	1.47%
2014	$ 5,623,875	1.61%
2015	$ 5,161,601	0.12%
2016	$ 4,504,081	1.28%
2017	$ 11,351,424	2.54%
2018		2.39%
2019		2.41%

	Collection	Withdrawals	Balance
2011	$ 2,000,000	$ -	$ 2,000,000
2012	$ 2,000,000	$ -	$ 4,000,000
2013	$ 2,000,000	$ -	$ 6,000,000
2014	$ 2,000,000	$ 5,623,875	$ 2,376,125
2015	$ 2,000,000	$ 5,161,601	$ (785,476)
2016	$ 2,000,000	$ 4,504,081	$ (3,289,557)
2017	$ 2,000,000	$ 11,351,424	$ (12,640,981)

succession planning allows employees to develop the skills deemed necessary from experienced employees who are performing the work at higher levels of responsibility.

Q. What are the specific FTE increases?

A. PGE Exhibit 802 provides detailed information on the additional positions. The vast majority of the FTEs are for capital work. Summary descriptions for the FTE increases include:

- Ninety FTEs to support strategic capital improvements identified in the T&D Risk Register as described in Part B, above. Examples of the job functions for these employees include specialized design for transmission and engineering, service and design project managers (SDPM), substation operations and engineering, and support staff such as contract management and fleet and garage operations.
- Approximately fifty-seven FTEs to support the increase in customer-driven capital work as described in Part B, above. Job function examples are Journeymen and Working Foreman Linemen, SDPMs to manage new customer connection projects, specialists to build capacity on the Geospatial Information Services (GIS), and service and design teams.
- Seven FTEs are required for compliance-driven activities. Complying with NERC standards requires additional FTEs as substation upgrades are executed and new substations require O&M support. In addition, FTEs are needed: 1) to address low service clearance within PGE's service territory to maintain compliance with NESC; and 2) for the new Joint Use Inspection program to support the inspection of electric

poles and associated communication attachments that are required to be compliance with the NESC.

- Approximately seven FTEs are needed for continuous improvement projects. These FTEs will help improve processes and create efficiencies in support of the distribution business and will support the following departments: Metrics, Field Technical Services, and T&D Project Services.
- Six FTEs are required for PGE's participation in the Western EIM, beginning October 1, 2017.
- Three FTEs are needed for engineering responsibilities that are part of PGE's Smart Grid initiatives. As PGE moves out of the planning stages of its Smart Grid Initiatives, these FTEs are needed to begin the design, engineering, construction and deployment of these initiatives.

Q. Are you also using contract labor?

A. Yes. PGE uses a balanced approach of contractors and internal labor to implement capital work. Using contractors allows us to address a number of labor needs, including, but not limited to: short-term assignments, specialized knowledge that may not be available in our market or at our wage levels, and for staffing up on projects that have a finite time frame and a need for a short-term influx of personnel.

We will continue to hire contractors to support over half of our capital construction work. The Underground Cable Replacement and the Proactive PCB Transformer Replacement Program will use contractors for this short-term work that is repeatable, programmatic, and easily measurable. Contractors will also be used for building many of our substations because this work is turn-key, fixed-price bid work, and the scope can be clearly defined.

PGE Exhibit 803 – 2018-2016 Incremental FTE Explanations

Driver	Department	Title	Increment Request	Description
Compliance	RC 364 Utility Asset Management	Analyst	1.00	Provide analytical support for T&D increases in capital work. Support Utility Asset Management with program evaluation and data modeling. This position is needed to provide support for evaluation of capital projects for transmission hardening, capital improvement programs, and engineering evaluation support. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code (NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 364 Utility Asset Management	Lighting Materials Project	1.00	Facilitate critically essential functions necessary to meet expectations of PGE's builder developer customers and Municipalities within our service territory. This position would be responsible for reviewing, analyzing, and consolidating PGE's luminaire and pole options offered to municipal and area light customers. This position is needed to address immediate customer satisfaction pain points (municipality, developer, and contractor) related to PGE's luminaire offerings, stocking levels, and installation commitments. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code (NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 364 Utility Asset Management	Project Manager	1.00	This position will be responsible for managing PGE's wireless collocation business and supporting our Joint Inspection and Correction program, which kicked off as a pilot program in 2016. On average, PGE receives about 60 wireless collocation (upgrades, repairs, new site) requests per year. Wireless make-ready (due to equipment, shutdown, coordination with customers, and contract requirements) can take anywhere from 6-18 months to complete. With the new systems and processes, a wireless designer can complete about 25-30 collocations per year, depending on the complexity of requests. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner

				inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for National Electric Safety Code (NESC) violations where practicable. This results in one trip to the pole instead of 2-8 trips.
Compliance	RC 594 Substation Operation Technology	Specialist, Operations and Planning Coordinator	1.00	The position is required to support NERC compliance with operations and planning standards for all of substation operations. The specialist will be the backup owner for all substation operations standards, including PRC-005, PRC-004, FAC-501 and others. The position will close gaps identified during our self-report and mitigation plan for PRC-005. They will also allow PGE to be proactive with NERC standards development to protect PGE's interest with regards to future regulations.
Compliance	RC 595 T&D Planning	Engineer, T&D Planning	1.00	The NERC compliance standards governing transmission continue to expand, requiring additional engineering resources to successfully fulfill PGE's compliance obligations. This includes new requirements for advanced studies such as geomagnetic disturbances and earthquake resiliency, as well as greater coordination of construction plans and transmission outage scheduling. Some transmission planning activities are being contracted out; however, the regional coordination aspect for more advanced transmission planning studies requires in-depth knowledge of PGE's system and operating practices. Because the new compliance standards are permanent in nature, a more permanent resource is needed.
Compliance	RC 595 T&D Planning	Specialist, Customer Equipment Violation	1.00	This position is needed to support the Low Clearance program. This program is a new regulatory requirement to address low services within PGE's service territory. In January 2015, the OPUC notified all Oregon electric utilities that overhead services with less than 10 feet of clearance to ground are in violation of the National Electric Safety Code (NESC) and would need to be corrected. In their notification, the OPUC explained that as a result of a recent IEEE interpretation of a clearance code in the 1961 edition of the NESC, electric utilities had mistakenly applied "grandfathering" to these services. Using data from recent inspections, it is estimated that 32,000 services within PGE's territory must be corrected as a result of this ruling. The overwhelming majority of these violations are the result of customer-owned facilities (weather heads and house brackets) that were installed too low to meet this clearance requirement.

Compliance	RC 595 T&D Planning	Specialist, Field Quality Assurance / Quality Control	1.00	This position is needed to support the Low Clearance program. This program is a new regulatory requirement to address low services within PGE's service territory. In January 2015, the OPUC notified all Oregon electric utilities that overhead services with less than 10 feet of clearance to ground are in violation of the National Electric Safety Code (NESC) and would need to be corrected. In their notification, the OPUC explained that as a result of a recent IEEE interpretation of a clearance code in the 1961 edition of the NESC, electric utilities had mistakenly applied “grandfathering” to these services. Using data from recent inspections, it is estimated that 32,000 services within PGE’s territory must be corrected as a result of this ruling. The overwhelming majority of these violations are the result of customer-owned facilities (weather heads and house brackets) that were installed too low to meet this clearance requirement.
Continuous Improvement	RC 018 T&D Special Project	Manager, Continuous Improvement	0.73	This position will manage the following groups: Metrics, Field Technical Services, T&D Project Services, and the Business Systems Administration. These groups make up the Continuous Improvement Projects team. This increases the currently budgeted position to a full-time role.
Continuous Improvement	RC 368 T&D Project Services	Administrator	1.00	Administrative support for the T&D Project Services department as they support Continuous Improvement projects.
Continuous Improvement	RC 368 T&D Project Services	Lead	1.00	This lead role is specific to the Metrics group within the Continuous Improvement team. This role supports and provides metrics to all T&D departments from the various systems used across T&D. This role will also head efforts to merge with PACE reporting over the next one to three years.
Continuous Improvement	RC 368 T&D Project Services	Project Manager	1.00	This position is moving from a sunset position to a FTE position.
Continuous Improvement	RC 376 Business Systems Administration	Analyst, Business	1.00	This is for the Business Systems Administration group as they support the new Continuous Improvement program
Continuous Improvement	RC 451 Field Technical Support	Specialist, Field Technician Support	1.00	This position is to support the increased amount of laptop operations and Automated Vehicle Locator in the field and vehicles and additional crews we are now supporting.
Continuous Improvement	RC 593 Transmission and Reliability Service	Specialist, Business Systems Integration, Settlements, and Billing	1.00	Provide systems and business process integration management for PGE Transmission and Reliability Services (T&RS) participation in bilateral and organized markets to enable efficient work processes. Align T&RS back office processes to support the on-going development and implementation of PGE’s Open Access Transmission Tariff, market rules, federal and regional regulations in

				coordination with T&RS staff.
Customer-Driven Capital Work	RC 305 Southern Line Crews	Journeyman Lineman	3.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 305 Southern Line Crews	Working Foreman Lineman	1.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Journeyman Lineman	3.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Supervisor, Line Field	1.00	Position supervises the Portland Service Center (PSC) line crews in the field, previews jobs before they are assignment to a crew, and meets with customers as needed. The work load at PSC for Line Field Supervisors (FS) requires more capacity than the two FS currently assigned to PSC can effectively handle. The average field checks per day per FS are more than any other Line Crew Center due to the complexity of working in the City Portland, and the amount of commercial customer work.
Customer-Driven Capital Work	RC 312 Eastern Line Crews	Working Foreman Lineman	1.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 314 Transmission Engineer and Specialized Design	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work.
Customer-Driven Capital Work	RC 315 Customer Power Quality	Critical Response Follow-up	1.00	Prepares and dispatches all T&D work for PGE Special Testers and Reliability Technicians. Create work orders that are high priority due to safety concerns or customer service through the life cycle of the job.

Customer-Driven Capital Work	RC 319 Geospatial Information Services	Specialist, GIS	4.00	These new positions are driven by the As-Built Operational Processes project. The As-Built Operational Processes project was set up to address the technology gaps and lack of process, role clarity, and capacity to process and post work in order to mitigate further backlog accumulation. Project goals include building capacity on the Geospatial Information Services (GIS) and Service and Design teams to ensure efficient and timely processing of work and utilizing best practices among peer utilities and evaluating the current state. The project steering committee has identified a strategy for the operational processes and resources needed to support the work load long-term.
Customer-Driven Capital Work	RC 319 Geospatial Information Services	Supervisor, GIS	1.00	This new position is driven by the rapid expansion of responsibilities and resources in the Geospatial Information Services (GIS) department. New responsibilities are being transferred to GIS from the Service and Design and IT functions of the business that will allow these departments to better focus on their core responsibilities. Given the increased responsibilities and resources in GIS, the existing management structure cannot adequately support supervision and development of employees within GIS and SAM as well as the programs and customers supported by these departments.
Customer-Driven Capital Work	RC 322 T&D Reliability Crews	Reliability Technician	1.00	Reliability Technician performs proactive inspections of overhead and underground T&D facilities for commercial customers with Quality and Reliability Program requirements. Currently PGE only has two Reliability Technicians that are challenged to complete growing annual inspection schedule, and increasing requests from Quality and Reliability Program customers for inspections.
Customer-Driven Capital Work	RC 323 Eastern Service and Design	Specialist, Service and Design Project Manager	1.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 324 Western Service and Design North	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 325 Southside Service and Design	Supervisor, Distribution	1.00	This is a supervisor for the Salem Specialize and Design Group. The second supervisor will be able to split the existing group into two departments. This will allow each supervisor more time to effectively coach and train employees, be more involved in project and design decisions, and to have more time for customer outreach.

Customer-Driven Capital Work	RC 326 Central Service and Design West	Specialist, Designer	4.00	Four additional designers are requested to work on the business owned as-built backlog. This backlog is separate from the Continuous Improvement project-owned backlog, and has resulted from insufficient capacity with the existing designers to work on as-built.
Customer-Driven Capital Work	RC 326 Central Service and Design West	Specialist, Service and Design Project Manager	1.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work.
Customer-Driven Capital Work	RC 329 Westside Line Crews	Journeyman Lineman	6.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 329 Westside Line Crews	Working Foreman Lineman	2.00	Linemen added to cover uptick in new connects and customer work.
Customer-Driven Capital Work	RC 336 Line Planning and Scheduling	Planner / Scheduler	1.00	Plan and schedule all T&D work for PGE and contract line crews. Works closely with Line Dispatchers, Operations/Field Supervisors, and Prerequisite coordination. We are converting the existing contractor position to a permanent position. It has become increasingly more difficult to get qualified contract employees. This increases instability in providing a well-planned, high density, schedule for PGE and Contract Line Crews.
Customer-Driven Capital Work	RC 339 Distribution Job Processing	Assistant	2.00	This position will review and validate line employee time. This will be a resource for line employees and Payroll. The position will also perform administrative tasks specific to the needs of line supervisors such as scheduling Oregon Department of Transportation (ODOT) physicals. Currently, there are no personnel in the regions to support timesheet entry or monitor time sheet accounting entry. Adding additional administrative assistance will reduce management costs associated with Corporate Planning, Claims Specialist and Line Supervisors who currently respond to time sheet and accounting issues, and will increase employee accountability for time and accounting entry. Adding FTEs will help ensure the estimated 2017 Line Operations combined O&M and Capital union payroll including Standard time, Over Time and premium pay, and will be processed timely and accurately.

Customer-Driven Capital Work	RC 346 Landscape Services	Chemical Spray Truck Driver	1.00	Assist current spray department employees in the mixing, transporting and application of pesticides used in PGE's vegetation management program in substations, generating plants, and company owned properties for compliance with the National Electric Safety Code (NESC). There are currently three spray crew employees applying herbicide to over 200 PGE owned sites. PGE continues to expand the number of facilities in order to fulfill customer demand. In just the last several years, PGE has added five substations, with construction of upcoming Marquam and Rock Creek Substations. However, we are at a point that we can no longer keep up with the weed growth at all sites. We cannot cover all of the locations with three people and stay ahead of the weed growth each year. Having the full two 2-person crew complement will allow us to successfully complete the substation treatments in the spring.
Customer-Driven Capital Work	RC 349 Line Prerequisite Coordination	Specialist, Prerequisite Coordinator	4.00	Supports Planning, Scheduling, and Line Dispatch departments through specialized knowledge of permitting requirements, and managing timing of pre-requisite activities to ensure optimal site readiness for crew arrival. Planning, Scheduling, and Line Dispatch has aimed to prepare a two week schedule, but has frequently been achieving 1-3 days out due to complexities of job preparation. Having a prerequisite coordinator to support the Planner/Scheduler results in denser schedules with longer lead times, fewer turndowns by the crew for site not being ready, more accurate adherence to external jurisdiction permitting requirements, and allows the Planner/Scheduler to focus on managing resource needs and work prioritization and balancing.
Customer-Driven Capital Work	RC 349 Line Prerequisite Coordination	Supervisor, Prerequisite Coordinator	1.00	The Supervisor for the new Line Prerequisite Coordination department is currently filled by a cross-trainer, and is needed as an FTE. Planning, Scheduling, and Line Dispatch have been attempting to provide a full days' schedule for crews since Maximo Mobile and Scheduling implementation. One of the critical enablers to the success of that process was creation of the prerequisite coordinator position, in 2016, and has proven to improve schedule density for crews.
Customer-Driven Capital Work	RC 353 Line Dispatch	Specialist, Line Dispatch	1.00	This position is needed to support the New Customer Connection Notification process that notifies customers of scheduled service installation. This is a necessary part of the process to greatly improve customer service. PGE has been trying to cover this work with the use of ongoing cross trainees, but has had difficulty getting qualified applicants. This job also needs a long-term position.

Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Field Inspector	1.00	Field inspectors are responsible for reviewing and analyzing permit requests to attach to PGE and external customer's poles. Field inspectors gather data from poles in the field, to determine through structural analysis, whether the structures are adequate to support proposed attachments. Using accepted design practices and analysis, inspectors ensure that support structures are maintained in compliance with applicable company standards and the National Electric Safety Code (NESC). Field inspectors routinely meet with other utility representatives and PGE General Foremen in the field to help determine the best design for correcting existing code violations and/or make ready for new licensee attachments. Field inspectors are responsible for ensuring that construction was performed in accordance with the design job and that licensees have attached in compliance with PGE requirements. Field inspectors may also be asked to manage projects of a utility or non-utility nature. Joint Inspection is a new program endorsed by the OPUC. The electric pole owner inspects all attachments on their poles as well as any communications poles in the map grid and provides physical corrections for NESC violations where practicable. This results in one trip to the pole instead of 2-8 trips resulting in savings for all parties.
Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Joint Use	1.00	Serves as a technical expert on the business operations team and provides operational support of utility Asset Management (UAM) technology, processes, and efficiency. Specific support for the Maximo Joint Use Portal (SharePoint) application, system enhancements and internal process improvements provided by our current employee cross-training in this position have proved very valuable. Therefore, we are making this a FTE position. This position has increased the efficiency of our internal processes through valuable process design work and IT support for PGE employees and allowed UAM to meet our joint use customers' expectations.
Customer-Driven Capital Work	RC 364 Utility Asset Management	Specialist, Service and Design Coordinator	2.00	There are two Service and Design Coordinators (SDC) needed. One SDC is a new position that will be responsible for streamlining street light materials, processes, and special projects that are outside of the normal Project Manager (PM) duties in outdoor lighting. Through customer surveys, and internal metrics it was brought to light, the rapidly changing lighting industry and technology, requires PGE to take an active approach to reducing our fixture offerings in some lines and increasing in others. The other SDC, determined after assessing increased customer demand because of the rising economy, is needed to meet contractor/developer demands. This position is a PM position, responsible for supplying residential development and

				municipality lighting designs/work orders for new street lighting, required for occupancy.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Specialist, Field Construction Coordinator	1.00	A fifth Field Construction Coordinator (FCC) is requested. Currently the four existing FCCs struggle to keep up with requested inspections and Field Supervisors (FS) provide backup and overflow coverage.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Specialist, Service and Design Project Manager	2.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. Also supports the delivery of PCB Replacement Program.
Customer-Driven Capital Work	RC 366 Central Service and Design East	Supervisor, Distribution	1.00	This position is to supervise at the Beaverton Line Center and support the increase in customer-driven capital work.
Customer-Driven Capital Work	RC 384 Specialized Design	Analyst, T&D Engineering	1.00	Provide analytical support for T&D increases in capital work. Support Transmission Engineering and Specialized Design with program evaluation and data modeling. In addition, it will provide support for evaluation of capital projects for transmission hardening, capital improvement programs, and engineering evaluation support.
Customer-Driven Capital Work	RC 384 Specialized Design	Engineer, Transmission Capital Projects and Planning	1.00	The engineer position will have program level responsibility for PGE's physical transmission assets. This position is needed to continually monitor and evaluate the physical transmission line assets and work to develop capital projects aimed at improving aging or failing infrastructure. This position will act as the engineering program manager with responsibilities for the transmission line inspection program, Transmission Maintenance and Inspection Plan (TMIP) regulatory reporting for FAC-501, Transmission R&D collaboration, and development of transmission projects aimed at correcting issues with aging transmission assets. Other responsibilities will include FERC/NERC compliance, outage/maintenance coordination, transmission asset management support, access road/ROW management, outage planning/prep, restoration planning, and infrastructure hardening.
Customer-Driven Capital Work	RC 384 Specialized Design	Specialist, Designer	1.00	This position will support new capital projects developed within the Transmission Engineering and Specialized Design group. Position will specifically be focused on transmission capital replacement projects, infrastructure hardening, and risk mitigation of existing transmission assets.
Customer-Driven Capital Work	RC 591 SVP Customer Service / T&D	Project Manager	0.73	Conversion of remainder of position to full-time and support the increase in customer work.

Increases in Capital Work	RC 023 System Control Center Support	Engineer, Systems and Control Center	2.00	Provide centralized quality assurance control for the substation operations electronic drawings management systems and asset documentation.
Increases in Capital Work	RC 203 Substation Operations	Engineer, Electric (Maintenance)	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 204 Substation Engineering	Design Engineer (Electric)	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 204 Substation Engineering	Engineer, Electric	3.00	These positions are required to address existing resource shortages and address the increases in capital work. Existing resource shortages in substation operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 204 Substation Engineering	Project Engineer (Electric)	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 204 Substation Engineering	Specialist, Designer	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 204 Substation Engineering	Substation Engineer	1.00	Additional Substation Engineering resource to support increases in capital work. Substation Engineers engineer Substations and provide technical review and oversight of contract substation engineering services.
Increases in Capital Work	RC 204 Substation Engineering	Supervisor	1.00	This position is to provide supervision of Engineering and Drafting personnel who perform engineering design and review of capital Substation projects. An additional manager will be required to provide adequate supervision, work review and employee development as a result of onboarding FTEs to support the increases in capital work.
Increases in Capital Work	RC 204 Substation Engineering	Technician, Drafter	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 209 Substation Technical Services	Relay Station Meter Technician	5.00	This position is required to address an existing resource shortage and address the increases in capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).

Increases in Capital Work	RC 213 Substation Operations Support	Assistant, Document Control	1.00	This position is to support the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 213 Substation Operations Support	Specialist, Scheduler	1.00	A new resource in substation operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 214 Substation Civil Construction	Civil Construction	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 216 Substation Maintenance	Contractor General Foreman	2.00	These positions are needed to oversee and coordinate the contract substation construction crews to support the increase in capital work. There are gaps in both the communication and execution of contracted substation construction. While the existing substation GF maintain and improve this process, they will not have the bandwidth to continue this activity with the hiring of additional contractors.
Increases in Capital Work	RC 216 Substation Maintenance	Wireman	6.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 217 Substation Operators	Substation Operator	1.00	This position is required to address the increases in capital work in regards to substation operations. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 218 Substation Communication Support	Communication Technician	6.00	This position is to support the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 232 SCADA Technical Services	SCADA Technician	2.00	There is a Supervisory Control and Data Acquisition (SCADA) Technician shortage and demand is only growing. This is a critical position for PGE's participation in the Western EIM, smart grid technologies, and T&D Strategic Asset Management (SAM).

Increases in Capital Work	RC 276 Contract Services & Inspection	Assistant	1.00	Administrative Assistance required for managing T&D contracts from creating requisitions to approval for payment, tracking PUC Service Level Agreement Inspections, Quality Control Programs and Staff processes. The forecasted capital work will raise Contract Services work substantially. Some work including the feeder replacement work for key customers, the Marquam Substation project, PCB transformer testing and replacement, and proactive cable replacement require more outsourcing and therefore, more contract management. Business Systems put in place over the past three years require more accurate and timely data to operate. Our current staffing levels cannot meet those needs for the current work. Strategic planning has established a consistent need for more services that require the additional administrative support.
Increases in Capital Work	RC 276 Contract Services & Inspection	Specialist, Construction Management	1.00	This position will support line operation's construction management and quality control assurance for T&D overhead and underground line construction and maintenance projects. Coordinate and manage contractor resources required to meet needs of Engineering, Service and Design Project Managers (SDPM) and T&D Line Operations. The continued growth in contractor utilization over the past four years has required hiring outside resources to meet quality control needs. Projected growth of capital work over next five year requires resources beyond current staffing. This has resulted in hiring temporary contractors to perform construction management, and Quality Assurance/Quality Control Inspection services. The increased work has generated requests for a higher level of strategy of quality assurance and construction management. This staff is currently the only internal resource with the workforce capable of meeting those needs. In addition, this department faces an exit of three people to retirement. Succession planning is needed to develop skills currently deemed necessary by Project Mangers, Engineering and SDPMs replacements while still preforming the work at increased level of responsibility.
Increases in Capital Work	RC 311 Distribution Engineering	Engineer, Electric	1.00	This position is to engineer substations to support the increases in capital work.
Increases in Capital Work	RC 311 Distribution Engineering	Supervisor, Distribution	2.00	These Supervisor positions (2) are to support the increase in capital work and to address the span of control within Distribution Engineering.
Increases in Capital Work	RC 314 Transmission Engineering and Specialized Design	Engineer	2.00	This position is to support the increases in capital work.
Increases in Capital Work	RC 314 Transmission Engineering and	Specialist, Designer	1.00	This position is required to address the increases in capital work in regards to PCB Transformer Replacement project.

	Specialized Design			
Increases in Capital Work	RC 314 Transmission Engineering and Specialized Design	Supervisor, Engineering	1.00	This position is needed to manage the 31 Potelco contractors and the upcoming four Service and Design Project Managers (SDPM) and one Lead SDPM for execution of the increases in capital work. This position and the positions reporting to this position will be needed long term to serve both current and future company business needs.
Increases in Capital Work	RC 324 Western Service and Design North	Specialist, Designer	1.00	This position is required to address the increases in capital work. New positions will be used in conjunction with a contractor strategy to effectively execute capital work.
Increases in Capital Work	RC 369 Engineering Design Services	Specialist, Service and Design Project Manager	7.00	To support the planning, scoping, estimating, and preliminary design of the increases in capital work. One of these FTEs will support the Underground Cable program by replacing underground cable and underperforming feeder reconductor. Another will support the delivery of PCB Replacement Program.
Increases in Capital Work	RC 369 Engineering Design Services	Supervisor, Distribution	1.00	A new supervisor position is requested for the Beaverton Service and Design group. The plan is to split the existing group into two departments, which will result in about nine employees per supervisor. Currently the supervisor has 17 reports, which is too large for effective coaching, training, continuous improvement work, and customer outreach. The requested position will be the replacement after the sunset position disappears, allowing us to keep the two supervisor's long term.
Increases in Capital Work	RC 585 T&D Project Management Operations	Analyst, Business	2.00	Supporting capital construction projects for the increase in capital work.
Increases in Capital Work	RC 585 T&D Project Management Operations	Project Manager	1.00	Planning Engineer for Substation Operations to support increases in capital work.
Increases in Capital Work	RC 585 T&D Project Management Operations	Project Manager, T&D Projects	1.00	No administrative support exists for World Trade Center-centered departments under T&D Asset Management. Departments requiring support are T&D Planning, Project Management, SAM, Geospatial Information Systems, and the organization manager.
Increases in Capital Work	RC 585 T&D Project Management Operations	Specialist, Programs	3.00	Scoping Engineer for Strategic Asset Management (SAM) to support increases in capital work.
Increases in	RC 585 T&D	Specialist,	1.00	Scoping Engineer for Strategic Asset Management (SAM) to support increases in

Capital Work	Project Management Operations	Scheduler		capital work.
Increases in Capital Work	RC 592 Strategic Asset Management	Scoping Engineer	2.00	This position will support the following initiatives: Strategic Asset Management, Substation Upgrades/Rebuilds, and Capacity Additions.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, Critical Infrastructure Protection	1.00	The Critical Infrastructure Protection (CIP) Specialist is a misnomer. While the job is related to CIP, it is really a Cybersecurity Specialist. Our current CIP specialists who deal with cybersecurity issues are focused on NERC CIP Compliance, which only applies to transmission stations. The majority of capital work is at distribution substations, so we have insufficient resources to support this work. The position will review control and protection designs for the substations to ensure they meet PGE security policy. They will review the CIP Compliance procedures used for transmission to determine the appropriate level of protection for our distribution system.
Increases in Capital Work	RC 594 Substation Operation Technology	Engineer, Electric	3.00	This position is to support the FTEs and processes due to the increases of capital work. Existing resource shortages in Substation Operations have been addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety).
Increases in Capital Work	RC 594 Substation Operation Technology	Engineer, Protection Transmission and Engineering	2.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, Operations and Planning Compliance	1.00	A new resource in Substation Operations addressed through excessive overtime, maintenance reductions, and lack of improvements (including safety) to support the increases in capital work.
Increases in Capital Work	RC 594 Substation Operation Technology	Specialist, SCADA Transmission and Engineering	1.00	This position performs testing and energization support for our Supervisory Control and Data Acquisition (SCADA) systems in the field. They help troubleshoot issues found during commissioning and serve as a liaison between the SCADA Technicians doing testing and the Automation Engineers who did the designs. The majority of the capital work is focused on deploying SCADA to Distribution substations, so the amount of SCADA work our team has to support has more than doubled. As such, we are going from one SCADA specialist to two.
Increases in Capital Work	RC 595 T&D Planning	Engineer, Electric	1.00	Position will support additional distribution planning responsibilities related to the increase in capital work. Position will provide insight and analysis that will influence new policies in the changing T&D landscape.

Increases in Capital Work	RC 596 T&D Asset Management	Assistant	1.00	T&D Asset Management has expanded roles and responsibilities in all groups located at World Trade Center. These new roles, along with increasing capital work and initiatives, require transitioning some administrative responsibilities off of managers and individual contributors who have been filling the gap.
Increases in Capital Work	RC 613 Eastside Warehouses	Storeroom	2.00	Increase in resources is driven by increased work volume, due to economy and miscellaneous capital projects. The eastern region storerooms need to support these increased crew levels. For the past year and a half, Storerooms have utilized cross training and temporary hires as a temporary solution. This is not optimal as temporary hires work up to six months before returning to their regular positions.
Increases in Capital Work	RC 614 Westside Warehouses	Storeroom	6.00	Westside Storerooms are understaffed for the volume of crews and work that are currently supported. Storerooms historically have operated on the basis of a 2:1 ratio – two crews can be supported by one Storeroom resource (SR). The current crew SR ratio for Western storerooms is 2.63 which cause jobs to be delayed, crews not leaving on time out of the yard, overtime to be used to get things done, and people burning out.
Increases in Capital Work	RC 615 Southern Warehouses	Storeroom	2.00	Increase in resources is driven by increased work volume, due to economy and miscellaneous capital projects. The eastern region storerooms need to support these increased crew levels. For the past year and a half, Storerooms have utilized cross training and temporary hires as a temporary solution. This is not optimal as temporary hires work up to six months before returning to their regular positions.
Increases in Capital Work	RC 632 Fleet and Garage Operations	Assistant, Fleet and Garage	1.00	Provides centralized procurement and financial controls for Distribution Operations and technical and administrative functions that support cross-functional groups. There are new regulatory requirements for driver and vehicle monitoring. With the continued addition of fleet vehicles requiring licensing and DEQ, the current position can no longer keep up with demand for data entry in systems.
Increases in Capital Work	RC 753 Enterprise Telecommunications	Communication Engineer	4.00	Position designs the communications infrastructure that allows our System Control Center and other centralized functions to get data from our remote facilities via Supervisory Control and Data Acquisition (SCADA), interchange metering and revenue metering. Increases in capital work involve upgrading substations in preparation for Integrated Grid functions, which requires the development of a robust communications infrastructure. Similarly, generation capital work will require additional communication circuits to power plants in support of reliability monitoring and security operations. While the full scope of the IT capital work have not been defined, it is expected that the communications infrastructure for our regional facilities and power plants will need to be enhanced to ensure a reliable and

				secure connection to the corporate network.
Integrated Grid	RC 023 System Control Center Support	Engineer	1.00	Position will perform the functions of a mid or senior level engineer for the development, configuration, maintenance of the Distribution Management System and its integration to control center applications such as Energy Management System and Outage Management System. While the Integrated grid project is shaping up, any such application (e.g. Distribution Automation, Distributed Generation (solar), distributed storage, and other advanced applications) will need to be managed from a central location, as well as integrated into System Control Center processes and systems. Current staffing is not adequate to support any Integrated Grid applications.
Integrated Grid	RC 311 Distribution Engineering	Distribution Engineer	1.00	Position focuses on smart grid deployment and operational planning/model development for the Portland area. As development continues, the need for more accurate day to day, near-term operational models has increased. PGE currently does not have a resource to develop and maintain an accurate power flow model for the Portland area. This resource will allow greater expertise and deployment support for smart grid technology in the Portland area.
Integrated Grid	RC 311 Distribution Engineering	Specialist, Distribution Maintenance	1.00	Position will support the distribution device maintenance program administration, tracking, and reporting. There is also a need to provide additional support to distribution device maintenance data cleanup, maintenance record updates, and reporting and metrics that we don't currently have resources for.
Western EIM	RC 014 T&D Dispatch	System Control Center Outage Coordinator	1.00	Position will be responsible for planning, coordinating, and scheduling transmission line outages with the CAISO, Peak Reliability Coordinator, BPA, and PacifiCorp (Labor in Exhibit 800).
Western EIM	RC 023 System Control Center Support	Energy Management System Engineer	1.00	Position will be responsible for the development, configuration, and full-time maintenance of new Western EIM computer systems and interfaces used by the System Control Center to support Western EIM participation (Labor in Exhibit 800).
Western EIM	RC 593 Transmission and Reliability Service	Analyst, EIM Policy	1.00	Position will be responsible for participating in the formation of regulatory and operational rules that impact the Balancing Authority's ongoing responsibilities in the market (Labor in Exhibit 800)
Western EIM	RC 593 Transmission and Reliability Service	Specialist, Western EIM Settlement and System	2.00	Position(s) will manage the Balancing Authority's ongoing settlement and settlement system responsibilities in the market (Labor in Exhibit 800)

Western EIM	RC 595 T&D Planning	Engineer, Transmission and Operation	1.00	Entry into the Energy Imbalance Market (EIM) requires PGE to maintain an accurate Full Network Model for use in Transmission Operations and by the Energy Imbalance Marketer. PGE's understanding of the NERC Compliance objectives for Transmission Operations, in conjunction with CAISO requirements for EIM participation, continue to evolve and will require additional engineering support beyond the resources currently available (Labor in Exhibit 800).
Total			**169.5**	

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Customer Service & CET

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kristin Stathis
Carol Dillin

February 15, 2018

Table of Contents

I. Introduction and Overview

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Kristin Stathis. I am Vice President of Customer Service Operations.

My name is Carol Dillin. I am Vice President of Customer Strategies and Business Development.

Our qualifications appear at the end of this testimony.

Q. Please summarize your testimony.

A. In our testimony, we explain PGE's forecast of Customer Service operations and maintenance (O&M) costs[1] for the 2019 test year and compare them to 2017, which represents PGE's most recent actual results. We also discuss the conclusion of PGE's Customer Engagement Transformation program (CET), which has been a comprehensive multi-year program (i.e., 2014 to 2018) comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large customer systems:

- The Customer Information System; and
- The Meter Data Management System.

Q. What is your primary goal for the Customer Service organization?

A. Our primary goal is to deliver exceptional customer experiences at a reasonable cost.

Q. How do you know if you are delivering exceptional customer experiences?

A. We gather customer feedback from residential and small/medium business and large business customers, which tells us whether we are delivering on our goal. Customer

[1] PGE's Customer Service costs are consistent with Federal Energy Regulatory Commission (FERC) Chart of Accounts categories: Customer Accounts Expenses and Customer Service and Informational Expenses (i.e., FERC accounts 902-908).

feedback is gathered in a variety of ways including quarterly, semi-annual, and annual customer satisfaction surveys; on-going surveys after specific customer transactions with PGE; and occasional customer focus groups or surveys on specific topics. In addition, we gather "voice of the customer" open-ended feedback through comments directed to customer service, to or about PGE on social media, on surveys, Public Utility Commission of Oregon (OPUC or Commission) complaints, and other sources. All feedback is used to identify areas of strength and areas of opportunity to improve PGE's service and to identify customer interest in new programs and service options.

Q. Have you seen changes in customer feedback over the years?

A. Yes. In general, PGE's customer satisfaction ratings have improved over the years. At the same time, industry satisfaction rates have also increased, raising the bar for average as well as exceptional performance. Our customers increasingly expect PGE to understand their needs and preferences. They expect us to offer services based on their needs. Compared to the past, they use media differently, moving from paper, landline phones and desktop computers, to mobile communications. Increasingly, we see many of our customers looking for green (clean energy) options and programs that support a decarbonized future.

Q. Please describe the functions of PGE's Customer Service organization.

A. Customer Service operations perform metering, billing, payment processing, collections, and responding to customers. The last category entails responding in a timely, courteous, and professional manner to customer requests received through various channels[2] such as the contact center, community offices, mail (postal or e-mail), mobile platform, Interactive

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[2] "Customer channel" refers to a method of customer interaction chosen by customers based on what services are available through that channel. Internet, Interactive Voice Response, mobile platform, and community offices are examples of distinct customer channels for payment.

Voice Response (IVR),[3] and by working directly with customers in their homes and/or places of business. Within Customer Service, we perform strategic activities including: 1) researching and collecting direct feedback from customers regarding their experiences and expectations; 2) monitoring customer feedback and satisfaction levels; and 3) developing and delivering new products and services that best meet customer needs.

Q. How do you perform these functions?

A. We perform these functions by providing timely and accurate customer usage data plus effective metering, billing, collection, and response services to all customers. We also focus on the implementation of other programs and service options such as demand response, paperless billing, on-line outage notification and text alert outage updates, and "one click" bill payment via email. In addition, we continue to research and evaluate the potential for other pilots and/or programs to enhance customer options and experience. Ultimately, we deliver value to our customers by providing exceptional customer service at a reasonable cost.

Q. How is your testimony organized?

A. In Section II, we explain PGE's request for forecasted 2019 O&M costs in comparison to 2017 actual costs. In Section III, we provide an update to the CET program, focusing on the Customer Touchpoints project, which is the largest component of CET (expected to be completed during the second quarter of 2018) and represents the replacement of PGE's Customer Information System and Meter Data Management System. In that section, we also discuss Customer Touchpoints in detail including its costs and benefits, and how the cost

[3] IVR refers to a call center technology that allows customers to use touch-tone telephones to interact with computer systems and complete self-service customer transactions.

estimate for the project has evolved over time. We provide concluding remarks in Section IV, and our qualifications are summarized in Section V.

II. Operations and Maintenance Costs

Q. What is PGE's forecast of Customer Service O&M costs for the 2019 test year?

A. PGE forecasts approximately $78.7 million in total Customer Service O&M for 2019, excluding uncollectible expense, which is a revenue sensitive cost. This represents a $10.0 million increase relative to PGE's 2017 actual costs. The overall increase to Customer Service is attributed primarily to cost escalation,[4] new or expanded programs, and charges/allocations for Information Technology (IT). Table 1 summarizes these costs, which are discussed in more detail below.

Table 1
Customer Service O&M Expenses ($Millions) and FTEs

Category	2017 Actuals	2019 Forecast	(2019-2017) Delta*
Labor (excluding CET)	$29.7	$32.8	$3.1
Non-Labor (excluding CET)	$16.3	$19.4	$3.1
Subtotal*	**$46.0**	**$52.3**	**$6.3**
CET Program Costs (Net)	$4.6	$0.0	($4.6)
IT Costs	$18.2	$26.5	$8.3
Subtotal*	**$68.7**	**$78.7**	**$10.0**
Uncollectibles	$5.5	$6.5	$1.0
Total Base Business Costs*	**$74.2**	**$85.2**	**$11.0**
FTEs	**464.5**	**455.1**	**(9.4)**

** May not sum due to rounding*

Q. What accounts for the increase in labor costs from 2017 to 2019?

A. The primary driver is wage and salary escalation, which is discussed in detail in PGE Exhibit 400. An additional reason for the O&M labor increase from 2017 to 2019 is that as the Customer Touchpoints project will be completed in 2018, approximately $0.5 million represents labor that shifts from capital to O&M as certain full time equivalent employees

[4] PGE Exhibit 200, Section I, provides the cost escalation factors that PGE used in developing its 2019 test year forecast. PGE Exhibit 400, provides additional detail regarding labor escalation.

(FTEs) move from building the new systems to running (i.e., operating and maintaining) them. As a matter of fact, Customer Service Operation's FTEs have declined by over 15 based on: 1) a 5.5 FTE reduction due to efficiency benefits that we expect to achieve as a result of Customer Touchpoints implementation; and 2) a 5.7 FTE reduction due to the conclusion of the program management office. We discuss the benefits in Section III, below.

Q. Please explain the forecasted increase in non-labor costs from 2017 to 2019.

A. In addition to cost escalation, the primary increase in Customer Service non-labor costs from 2017 to 2019 is a function of outside services to support the following:

- Approximately $2.4 million for the Flex Pricing pilot to be a fully scalable, demand response program in 2019. PGE initiated the Flex Pricing pilot in 2015 in accordance with Commission Order No. 15-203 (Docket No. UM 1708). The pilot constitutes a significant effort to meet the expectations for informational benefits[5] from PGE's advanced metering infrastructure system (AMI), which can now be achieved in conjunction with the implementation of PGE's Customer Touchpoints project. Consequently, we are using the information and lessons learned from the pilot and its evaluations to determine the appropriate time-of-use prices, peak time rebate, and applicable time periods for the opt-in, fully scalable demand response program.
- Approximately $0.7 million for the following projects/activities:

[5] Informational benefits are distinguished from operational benefits, which PGE established in Docket No. UE 189 (estimated operational benefits) and confirmed in subsequent reports to the Commission in 2012 (actual operational benefits).

- Funding a study to research and forecast the load impact of residential appliance saturation. This study is performed periodically, with the most recent performed in 2013. The study estimates the saturation of residential technologies related to heating, cooling, water heating, electric vehicles, etc. The uses of the study are varied and include: load forecasting for summer peaking and winter peaking, Integrated Resource Plan enabling studies to determine the potential for demand side management, and estimating market size for new program development (e.g., direct load control demand response).
- Evaluating the integration on our system of the growing number of distributed energy resources (e.g., smart solar inverters, advanced thermal storage technologies, and smart charging of electric vehicles).
- Facilitating commercial, industrial, municipal, and non-profit customer adoption, procurement, and installation of electric vehicles and electric vehicle charging infrastructure for fleets and workplace. This activity will support non-residential customers in evaluating opportunities for electrifying fleet vehicles, make recommendations for charging infrastructure sizing and siting, and estimate total cost of ownership. Technical specialty areas include but are not limited to the following energy systems: electric vehicles (cars, buses, light and heavy duty vehicles, bikes, and other electric devices used for mobility), charging stations, charging standards, AC and DC power, power electronics, and smart charging.

Q. What are the CET program costs and why do they decline from $4.6 million in 2017 to zero in 2019?

A. The CET program costs represent program development O&M that was incurred from 2014 through 2018 and has been subject to deferred accounting treatment. In accordance with Commission Order No. 17-511, these costs have been moved from PGE's 2018 base rates to Supplemental Schedule 112 and are not included in our 2019 test year forecast.

Q. Do you address IT costs in this testimony?

A. No. Because IT costs are charged or allocated to all operating areas of the company, they are discussed in detail in PGE Exhibit 600.

III. Customer Engagement Transformation

A. Overview

Q. Please provide a brief summary of the CET program.

A. The CET program is a set of initiatives targeted specifically at the Customer Service functional areas. The CET program includes both large and small initiatives that focus on process improvements, business strategies, operational efficiencies, employee development, and replacement of PGE's Customer Information System (CIS) and Meter Data Management System (MDMS). Modern customer systems support the capabilities that are desired by our customers plus the products and services enabled by the smart grid, and they provide more opportunity for automation. As noted in Section I above, we refer to the effort to replace the CIS and MDMS as the Customer Touchpoints project.

Q. Why are you replacing these systems?

A. PGE's current CIS and MDMS have been prudent investments for our customers, but have been in use since 2002 and 2000, respectively. Consequently, they are over 15 years old and are so outdated that they are no longer supported by the product vendors. This means that they are not technically or functionally suited for existing programs, such as billing for net metering, emerging smart grid requirements, or new pricing options. Further enhancements and changes to existing systems would be costly and slow, leading to even more manual processes as the systems become more aged and obsolete. Replacement is critical to continuing operations because the cost to maintain the old systems and the risk associated with them increase the longer we wait.

In conjunction with replacing these systems, we are taking advantage of opportunities to make improvements such as implementing more efficient billing through automation and improving key business processes that have an impact on the customer experience. The additional functionality that comes with the new systems will provide PGE with opportunities to improve the way we engage and serve our customers.

Q. What alternatives did PGE evaluate for the Customer Touchpoints project and on what basis did PGE make its selection?

A. PGE selected Oracle's Customer Care and Billing solution (CC&B) to meet our CIS needs based on a fit-gap analysis to determine the best system for PGE. This analysis is provided as confidential PGE Exhibit 901C. PGE made this selection between two CIS market leaders, SAP and Oracle, both of which have enough market share and financial capacity to continuously improve their products and adapt to new utility technology trends.

We evaluated both solutions for alignment with PGE's technology strategy and our ability to fulfill operational requirements. Only Oracle CC&B, however, also fulfills PGE's stated IT goal of strategic sourcing where we will move towards having fewer, deeper vendor relationships.

To select the replacement MDMS, PGE conducted a request for proposals. As a result of that effort, PGE chose the Oracle solution based on the combination of cost and features, as well as meeting the strategic goal described above.

B. Implementation

Q. What activities have you completed to implement CET?

A. In addition to completing the Customer Touchpoints project, PGE has completed several operational efficiency projects under CET, including:

- Contact Center Improvements – Helped reduce average call handling time, improved the effectiveness of forecasting and scheduling processes, and freed up capacity that was redeployed toward improving service levels.

- Billing and Credit – Simplified reports used by the billing and credit departments that reduced nearly 12,000 monthly manual bill reviews.
- Paperless Bill – Focused effort on increasing paperless bill enrollment, increasing participation to over 36% of customers.
- Knowledge Management – Provides a standardized, searchable, single-source knowledge management system so customer service employees can quickly access information they need to serve customers.
- Quality Customer Interactions – Improves the quality of interactions between Customer Service Operations (CSO) employees and customers by improving the process for receiving customer feedback and standardizing CSO's quality assurance and performance programs.
- Workforce Management – Improves the effectiveness of workload forecasting and optimizing employee schedules throughout CSO, freeing up capacity that can be applied toward improving service levels or reducing costs.
- People Development for CSO – Identifies and develops new skills to build workforce capabilities for the future, enable CSO to adopt new systems and processes, and continue to improve customer service and operational efficiencies.

Q. What have you completed with respect to the Customer Touchpoints project?

A. As noted above, the Customer Touchpoints project refers to the replacement of PGE's CIS and MDMS. To accomplish this, we achieved several milestones under building, testing, and training activities, including:

Building

- PGE has finalized the build-out of the new CIS and MDMS and completed embedded and end-to-end testing to ensure that all business processes work as designed, and that bills can be produced accurately and timely. To accomplish this build-out, we have:

- o Licensed Oracle's CC&B and meter data management solutions, along with seven other Oracle modules for the meter-to-cash and customer service and support functions of the business.
- o Implemented iterative design and build cycles. The technology is continuously delivered across three cycles of building new functionality and testing future-state processes in the system.
- o Conducted data cleansing.
- o Completed system-design requirements, with hardware and software installed.
- o Ensured that data and process-integrity remain intact through rigorous system build-out and testing.

Testing

- Continued testing the new systems by performing "dry-runs" or practice "go-lives" to validate system stability and performance.
- Performed mock data conversions and data migration so the new systems can perform dry runs in parallel to the existing systems. This included bringing hardware memory and capacity up to production levels.
- Completed operational readiness testing to verify bill accuracy, compare operations against the legacy systems, and simulate real-life business scenarios.
- Tested all meter-to-cash system components.

Training

- Supporting employee adoption of new processes and systems by designing and delivering various pre-training activities, providing employees an overview of the new systems, and supporting leadership as they guide the workforce through these significant changes.

- Set the baseline metrics and service levels for all groups that will be using the new CIS and MDMS so that we can determine how these metrics will adjust with the new processes and systems. Ultimately, these metrics will help us determine that the systems have been stabilized and we are back to "normal" business.
- Completed business readiness activities including:
    - Communicated role profiles with employees, which define their job responsibilities after "go-live" and determine what training they will receive.
    - Established a support model for planning and reporting to assist PGE in managing staffing levels through system stabilization.
- Launched formal training for approximately 450 employees and contractors. This includes practice sessions on previously trained material to improve retention and increase proficiency.
- Established responsibilities, organizational structure, and resource requirements for system support up to "go-live" and system stabilization after "go-live".

Q. What activities are you currently performing to complete Customer Touchpoints and ensure the systems will be operational during the second quarter of 2018?

A. We are performing our final mock data conversions and dress rehearsals of the new systems in parallel with the existing systems to evaluate system performance, identify variances, and implement fixes as necessary. In addition, the system users are continuing in-depth training so they are prepared to operate the systems at "go-live".

Q. Has PGE managed the scope of the project to achieve necessary functionality while limiting the overall cost?

A. Yes. PGE's Customer Touchpoints project uses an integrated Change Control process for managing changes in a controlled manner. This process consists of the following key tools:

- Change Request – All changes to scope, schedule, and cost are documented using the Program's Change Request template.
- Change Request Log – This is essential for tracking proposed Change Requests and managing the Integrated Change Control process. PGE's Customer Touchpoints project maintains this log in an enterprise-wide program management application.
- Decision-making Authority – The Program's Decision RACI definition document (Responsible, Accountable, Consulted, Informed), authorizes the designated committee and project leaders to be responsible for approving and rejecting requested changes.

Q. When do you expect the new CIS and MDMS to be operational?

A. We currently estimate that the two systems will "go-live" during the second quarter of 2018. Consequently, as noted in PGE Exhibit 200, the Customer Touchpoints assets will be included in PGE's test year rate base, which is determined by year-end 2018 balances.

Q. Had PGE included the Customer Touchpoints project in its previous general rate case?

A. No. Although Docket No. UE 319 (UE 319) was based on a 2018 test year forecast, rate base in that proceeding was established as of year-end 2017. This means that capital costs and on-going O&M associated with Customer Touchpoints were not included in UE 319 or in prices approved by Commission Order No. 17-511. As noted in Section II, above, PGE did incur program development O&M costs associated with the CET program from 2014 through 2018, but these costs have been deferred separately and the remaining balance will be amortized over five years through a supplemental schedule that began January 1, 2018.

Q. How does PGE plan to achieve cost recovery for Customer Touchpoints for the period from "go-live" through year-end 2018?

A. Because PGE will otherwise not recover its post-"go-live" costs for Customer Touchpoints until prices for this general rate case go into effect on January 1, 2019, PGE plans to file a request for deferred accounting treatment for all costs related to Customer Touchpoints from "go-live" through year-end 2018. This deferral will be subject to ORS 757.259[6] and will, if approved, allow PGE to recover prudent costs associated with used and useful assets that are providing benefit to customers.

C. Benefits

Q. Please describe the benefits that the Customer Touchpoints project will provide.

A. In addition to replacing obsolete systems, the Customer Touchpoints project provides numerous benefits based on "out-of-the-box" functionality, which is more responsive to customer needs and will allow customers to:

- Make one-time check payments over the phone; currently customers are redirected to the IVR system or the PGE website to make a payment.
- Enroll in Auto Pay or update bank account information over the phone.
- Choose the specific date their bill will be due, instead of the bill cycle (date range), helping customers better plan and manage their cash flow.
- Enroll in the Preferred Due Date program with fewer restrictions, making it more accessible to customers who could benefit the most.

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[6] At this time, the potential to defer "return on" investment is subject to investigation in Docket No. UM 1909.

- Keep their new account number permanently (when new systems are implemented), even when they move to a different address within PGE's service area.

Finally, the new CIS will support more varied pricing options compared to what is available with our current system.

Q. Has CET provided, or will it provide, cost savings for PGE customers?

A. Yes. Although the decision to implement CET was based on the obsolescence of PGE's legacy systems and the availability of mature utility customer systems with established functionality, PGE estimates that we will achieve annual O&M savings of $3 million to $5 million on an incurred basis once the program is complete. These savings can be summarized as follows:

- A reduction of 33 FTEs between 2013 and 2016 and an additional 5.5 FTE reduction that is projected in 2019 after the systems are stable and operating. These reductions have allowed the CSO to reduce its FTE count from 407 in 2012 to a projected 380 in 2019 with some offsetting increases due to other factors such as customer growth.
- Approximately $1.0 million in non-labor cost reductions due to the paperless billing program. This savings will continue to grow as customer participation in the program increases.

Q. Are there any other benefits associated with the new systems?

A. Yes. As noted in UE 319 (PGE Exhibit 2100), PGE had analyzed the cost to continue operating the existing legacy systems and estimated that we would incur approximately $63 million in additional O&M costs over ten years if we did not implement the CIS and MDMS replacement project. We based this analysis on a presumed expansion of customer-based technology adoption that would impact the legacy systems (e.g., electric vehicles and distributed customer generation). This represents an avoided cost benefit of implementing Customer Touchpoints.

D. Costs

Q. What is the total cost of the CET program?

A. The total cost of the CET program is currently estimated to be $150.0 million in capital and $27.5 million in program development O&M costs. Of the total capital cost, the Customer Touchpoints project, representing approximately $147.5 million, is the final (and largest) component to be completed. We expect Customer Touchpoints will become operational in the second quarter of 2018. PGE Exhibit 902 provides the amounts of capital that become operational by year.

Q. Over what period of time will the capital costs be depreciated or amortized?

A. The software capital costs will be amortized over ten years, which as noted in PGE Exhibit 200, is typical for larger software projects. The hardware costs will be depreciated over five years as specified by PGE's approved depreciation study (Docket No. UM 1809).

Q. Are the Customer Touchpoints capital costs included in PGE's proposed prices effective January 1, 2019?

A. Yes. Because PGE has set rate base in this filing as of December 31, 2018, and Customer Touchpoints goes live in 2018, they are part of the prices that would go into effect on January 1, 2019.

Q. Has the estimated capital cost of Customer Touchpoints changed over time?

A. Yes. The change, however, was based on a logical progression of research, in-depth inquiry, consultation with third-party experts, and experience acquired over time as we advanced through stages of implementation. In short, cost estimates for large, complex IT systems typically evolve over time as preliminary estimates become more refined and additional information and experience is acquired.

Q. Please describe the process you used to develop your capital cost estimates for Customer Touchpoints.

A. Three years prior to substantially beginning to implement the Customer Touchpoints project, our first cost estimate was $57-$66 million. This estimate, however, was very preliminary because it was based on:

- Initial research that needed to be followed by much more in-depth inquiry; and
- Incurred capital costs only, but not including loadings, allocations, or allowance for funds used during construction (AFUDC), which at the time were estimated to be approximately $13-$14 million.

Q. How did your estimate evolve from there?

A. To develop a more in-depth and accurate estimate, PGE performed the following activities:

- Identified the software systems necessary to enable specified business capabilities and replace obsolete technology.
- Engaged third-party TMG Consulting (TMG) to support our contract negotiations for System Integration. This effort involved TMG providing analyses and cost targets for the software to replace PGE's existing CIS and MDMS.
- Engaged third-party Emtec Consulting (Emtec) to evaluate the CIS/MDMS scope and cost comparisons in order to benchmark PGE's costs to implement the proposed system against other utilities with comparable implementations.
- Substantially negotiated a contract with Oracle Utilities for their suite of software products.

- Substantially negotiated a contract with Accenture for System Implementation services.
- Conducted a bottom-up re-estimate of the effort to integrate the new CIS and MDMS to existing PGE applications using technical staff assigned to the project.

Q. Did PGE expand the scope of the Customer Touchpoints project by adding significant functionality?

A. No. We identified other functionality and/or activities that had not been captured in the initial estimates, but were needed to meet scope and maintain current functionality including:

- Web functionality – costs to convert PGE's website to utilize the new CIS's data structure and retain existing self-service functionality.
- IVR – costs to convert the IVR to utilize the new CIS data structure and retain existing functionality.
- Knowledge Management – provides a tool to serve as the single source of reference for the CSO's policies, processes, and working procedures, and replaces PGE's current knowledge management system, which is obsolete. This will be the primary source for instructions on how to use the system, which will be leveraged to train customer service representatives on the new system and support their day-to-day interaction with customers after training.
- Bill Presentment – costs to convert the equipment that produces bills, notices and letters to utilize the new CIS's data structure and retain existing functionality.

In summary, PGE started with a very preliminary estimate of incurred costs based on limited information. We then updated the program for additional activities to retain current, necessary functionality and identified suitable software systems. After a detailed bottom-up analysis, we engaged two third-party consultants to: 1) provide analyses and cost targets for the replacement systems; 2) support contract negotiations for system integration; and 3) benchmark PGE's projected costs to other utilities with comparable implementations. With this support and information, we negotiated contracts for software products and system integration. With each step, we had more refined information with which to estimate our costs, which were also updated for loadings, allocations, and AFUDC.

Q. Does this type of process typically involve significant changes to cost estimates for large software projects over time?

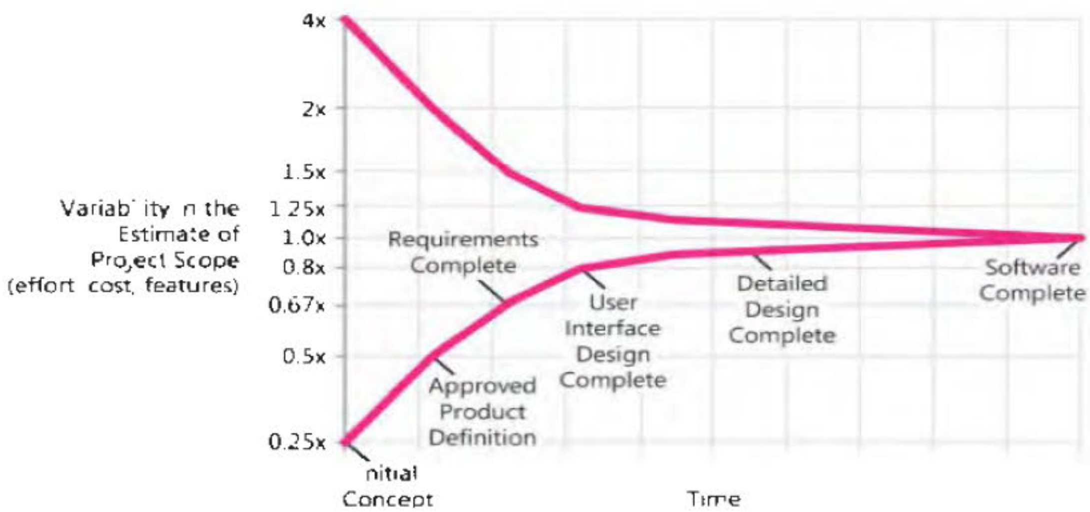
A. Yes. Estimates for the cost of large, enterprise-wide computer applications can vary significantly depending on the implementation stage of the project. The Avista Corporation correctly summarized this concept in OPUC Docket No. UG 284 (Avista/501, page 37) by stating:

> Early in the scoping of a software project, particular details of the application being designed/installed, a detailed knowledge of the Company's specific business requirements, details of the solution sets, the management plan, identified staffing needs, and many other variables are simply unclear. Accordingly, estimates of the potential cost of the project are highly variable. As these sources of variability continue to be investigated and reduced, the project uncertainty decreases; likewise, so does the variability in estimates of the project cost. This phenomenon, widely discussed in the literature, and often associated with author Steve McConnell,[7] is known as the "Cone of Uncertainty".

[7] Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006.

Figure 1, Cone of Uncertainty[8]

The 'Cone of Uncertainty' describing the relationship between the variability in the estimates of a software projects' costs and the stage of the project at which the estimates are developed.



In short, there is significant uncertainty in the early stages of developing estimates of the cost and time necessary to complete major software projects.

Q. At what phase of the project did PGE provide the initial Customer Touchpoints estimates?

A. PGE provided the initial estimates in Docket No. UE 262 (filed in February 2013) during the initial concept stage: before software and system integrators were selected, and before all requirements were finalized.

Q. What phase of the project is Customer Touchpoints in now?

A. As shown in PGE Exhibit 903, we have completed the detailed design and testing phases of the Customer Touchpoints project and currently are in the final completion phase so as to go live in the second quarter of 2018.

[8] Ibid. Figure No. 4-2, page 37.

Q. Based on the process you described above, how did your estimates of Customer Touchpoints capital costs evolve?

A. PGE Exhibit 903 summarizes the estimates that PGE created by date and identifies where in the process these occurred. We describe these further as follows:

- $57 to $66 million total capital cost at initial concept. PGE had developed this estimate in 2012, but submitted it in February 2013 as part of our 2014 general rate case (Docket No. UE 262, Confidential PGE Exhibit 904C).
- $99.3 million total capital cost at approved product definition in October 2014. The increase from the original $57-$66 million reflects the following items (specific dollar amounts were not attributed to the individual changes at that time):
    - o Increased costs to reflect loadings, allocations, and AFUDC.
    - o Increased software costs for additional modules to meet project scope.
    - o Reduced hardware costs due to revised engineering estimates.
    - o Better understanding of additional work necessary to integrate existing applications, as performed by PGE and not supported by the system implementation contract.
    - o Includes consolidate bill print technology, and enables web, IVR, and mobile technology.
- $137.0 million total capital cost after completing requirements in October 2015. This increase from the $99.3 million is due to the following:
    - o $7 million increase due to additional software modules to meet project scope.
    - o $4 million decrease due to revised estimates for hardware.

- o $5 million decrease based on results of negotiating the system implementation contract.
- o $15 million increase due to better understanding of the work necessary to integrate existing applications not supported by the system implementation contract.
- o $9 million increase based on a re-categorization of costs from O&M to capital to comply with generally accepted accounting principles.
- o $6 million to increase the program contingency to 20% of incurred costs to reflect industry standard.
- o $6 million to reflect increased loadings as a function of increased internal labor.
- o $3 million to reflect an increase in AFUDC based on a change in estimated closing assumptions and increases in other cost estimates.

- $137.5 million total capital cost in April 2016.
- $137.5 million total capital cost as estimated in February 2017. PGE prepared this estimate before completion of the detailed design.
- $147.5 million current estimate as of February 2018. This cost increase reflects the potential for: 1) mitigation of below-average data conversion accuracy and greater than estimated time to complete the "go-live" conversion process; and 2) a larger than expected volume or severity of defects. In spite of this increase, the total cost estimate for the program has been fairly stable since October 2015 (at commencement of the Customer Touchpoints project).

Q. How does PGE's cost estimate compare with other similar systems?

A. PGE conducted extensive research for selecting the appropriate systems to implement and, as noted above, employed Emtec, a third-party consultant, to evaluate and benchmark PGE's alternatives. Emtec's study concludes that PGE's cost is within their benchmark range (see PGE Exhibit 904C for the Emtec study, in particular slide 13, the row titled "Total w/Contingency" under the "Total" columns and slide 18). This conclusion is still valid based on PGE's current estimate of incurred cost for Customer Touchpoints, which we summarize in PGE Exhibit 905C.

Q. Are any CET program development O&M costs included in PGE's proposed prices effective January 1, 2019?

A. No. As noted in Section II, above, in accordance with Commission Order No. 17-511, CET program development O&M costs have been moved from PGE's base prices to Supplemental Schedule 112 and are not included in PGE's 2019 test year forecast.

Q. Are there any incremental on-going O&M costs included in your 2019 forecast?

A. Yes. PGE's 2019 test year forecast includes amounts for software license fees associated with the new CIS and MDMS, plus approximately $2.1 million for applicable property taxes. In addition, as noted in Section II, above, approximately $0.5 million in labor represents a shift from capital to O&M as certain Customer Service FTEs move from building the systems to running them. Additional IT-specific O&M costs also relate to running the new systems but these are discussed in PGE Exhibit 600.

IV. Conclusion

Q. Please summarize your proposal with regard to Customer Service costs in this proceeding.

A. PGE requests that the Commission approve PGE's forecasted increase in Customer Service O&M costs as described in Section II above, to be effective January 1, 2019. These costs are necessary for PGE to provide timely and accurate customer usage data plus effective metering, billing, collection, and response services to all customers, as well as develop and implement new programs and service options that provide benefits to customers.

We also request that the Commission approve the costs associated with the completion of the Customer Touchpoints project, which reflects $147.5 million in capital for the CIS and MDMS replacements, as described in Section III, above. The new systems are scheduled to be operational in the second quarter of 2018. To provide cost recovery for the new systems in 2018, PGE plans to file a request for deferred accounting treatment for all costs related to Customer Touchpoints from "go-live" through year-end 2018. Granting cost recovery for Customer Touchpoints in 2018 (through approval of the deferral and subsequent amortization) and in base prices (effective January 1, 2019), will allow PGE to recover reasonable and prudent costs associated with used and useful assets that are providing benefit to customers.

V. Qualifications

Q. Ms. Stathis, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Political Science from Willamette University and a post-baccalaureate certificate in accounting from Portland State University. I previously qualified as a certified public accountant in the State of Oregon. I am on the boards of Marylhurst University; the Oregon Alliance of Independent Colleges and Universities; the Western Energy Institute, and the PGE Foundation. I serve as Vice President, Customer Service Operations, at PGE and have been in this role since June 2011. In this position, I am responsible for operational functions including metering, billing, credit and collections, community offices and the contact center. I began my career with PGE twenty-four years ago as a financial analyst. Since then, I have served in a number of roles including Assistant Treasurer and Manager of Corporate Finance, General Manager of Power Supply Risk Management, and General Manager of Revenue Operations.

Q. Ms. Dillin, please describe your qualifications.

A. I received a Bachelor of Arts in Journalism and Spanish from the University of Oregon. I have taken post-graduate business courses at Marylhurst University, and am a graduate of the American Leadership Forum class of 2005. I am on the boards of The Center for Women's Leadership, PGE Foundation, BEST, and the Business Advisory Council for Portland State University. I serve as Vice President, Customer Strategies and Business Development at PGE and have been in this role since June 2011. In this position, I am responsible for the Retail Customer Strategies for PGE. This includes Customer Research and Analysis, Customer Program Development and Management, Retail Technical Strategies, Business Customer Group, Smart Grid, R&D, and Economic Development. Since beginning my career at PGE twenty-nine years ago, I have served in a number of roles including Public Information Specialist; Director, Corporate Communications and Community Affairs; Vice President, Public Policy; and President of the PGE Foundation.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit 901C

Protected Information Subject to Protective Order 18-047

Asset Category	Account	2015 Actuals	2016 Actuals	2017 Actuals	2018 Forecast	Totals
Customer Touchpoints						
software - 10 year amortization	303	$ -	$ 1,908,654	$ -	$ 139,798,094	$ 141,706,748
computer	39102	$ 352,970	$ 512,173	$ 5,699,127	$ (1,184,200)	$ 5,380,070
furniture	391	$ 225,498	$ 154,092	$ 57,267	$ -	$ 436,857
		$ 578,468	$ 2,574,919	$ 5,756,394	$ 138,625,779	$ 147,523,675
Other CET						
software - 10 year amortization	303	$ 533,405	$ 1,632,895	$ -	$ -	$ 2,166,300
computer	39102	$ 100,564	$ 114,304	$ 74,630	$ 148	$ 289,646
furniture	391	$ -	$ -	$ 41,031	$ -	$ 41,031
		$ 633,969	$ 1,747,200	$ 115,661	$ 148	$ 2,496,978
Total CET						
software - 10 year amortization	303	$ 533,405	$ 3,541,549	$ -	$ 139,798,094	$ 143,873,048
computer	39102	$ 453,534	$ 626,477	$ 5,773,757	$ (1,184,052)	$ 5,669,716
furniture	391	$ 225,498	$ 154,092	$ 98,298	$ -	$ 477,888
		$ 1,212,437	$ 4,322,119	$ 5,872,055	$ 138,614,042	$ 150,020,653

Customer Touchpoints Capital Costs within the "Cone of Uncertainty"*

*Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006

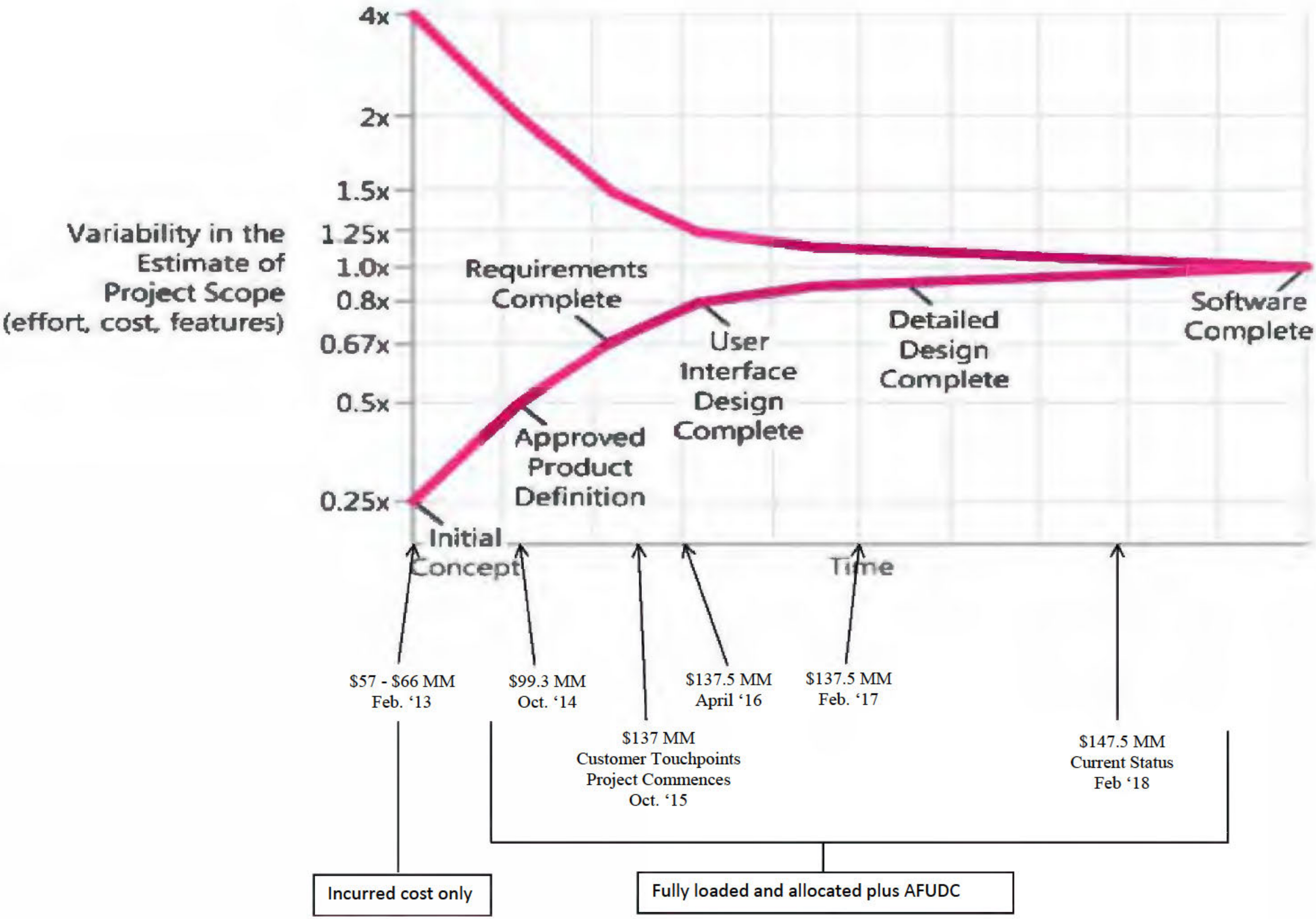


Exhibit 904C

Protected Information Subject to Protective Order 18-047

Exhibit 905C

Protected Information Subject to Protective Order 18-047

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
Christopher Liddle
Bente Villadsen, Ph.D.

February 15, 2018

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing Portland General Electric Company's (PGE) cost of capital.

My name is Christopher Liddle. I am the Assistant Treasurer and Manager of Treasury and Investor Relations for PGE. I am responsible for managing the company's treasury function including financing.

My name is Dr. Bente Villadsen and I am a principal at The Brattle Group (Brattle). My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138. I have been asked by PGE to estimate the cost of equity that PGE should be allowed an opportunity to earn on the equity portion of its rate base for the period beginning January 1, 2019.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to recommend PGE's cost of capital and capital structure for the 2019 test year. PGE recently concluded a general rate case, Docket No. UE 319, where parties initially challenged PGE's recommended cost of capital and capital structure, and ultimately settled these issues. This settlement was approved in Order No. 17-511 in December 2017. PGE is not recommending changing the return on equity (ROE) or capital structure authorized in that order, and proposes only to update its cost of debt to reflect slightly lower costs.

Maintaining PGE's current cost of capital and capital structure is necessary to support its credit profile for access to the debt and equity markets, to fund its capital investments planned for 2019, and to provide PGE the opportunity to earn a fair return for equity shareholders while keeping its costs reasonable. Guidance regarding the appropriate authorized cost of capital is provided by the Bluefield[1] and Hope[2] United States Supreme Court decisions, as well as ORS 756.040.

Q. What is PGE's requested overall cost of capital for this filing?

A. We request and support a 7.312% cost of capital for the 2019 test year. This cost of capital reflects PGE's currently authorized ROE of 9.50%, its currently authorized capital structure of 50% debt and 50% equity, and an updated long-term cost of debt of 5.123%. To demonstrate the reasonableness of maintaining PGE's current ROE, we have produced a recommended range for PGE's authorized ROE and 9.50% is at the lower end of that range.

Table 1 below, shows the recommended cost of the two components of PGE's capital, common equity and long-term debt. Table 1 also shows PGE's forecasted 2019 capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2019

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,481,956	50%	5.123%	2.562%
Common Equity	$2,553,639	50%	9.500%	4.750%
Total	**$5,035,595**	**100%**		**7.312%**

[1] "Average Outstanding" reflects PGE's projected average values of long-term debt and common equity for 2019.
[2] "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital ("Weighted Cost").

Q. How is the remainder of your testimony organized?

A. In the following section, we describe PGE's financial goals and how PGE manages counterparty risks and liquidity. Section III provides a review of financial and market regulation changes as well as the recent and near-future financial market and economic

[1] Bluefield Water Works v. Public Service Comm'n - 262 U.S. 679 (1923).
[2] FPC v. Hope Nat. Gas Co. - 320 U.S. 591 (1944).

conditions. We also briefly discuss the recent Tax Cuts and Jobs Act of 2017 Reform Act (tax reform) and its expected impact on PGE's cost of capital. We discuss PGE's cost of long-term debt, including new and redeemed issuances, in Section IV. In Section V, we provide the updated analysis that supports maintaining PGE's ROE at its current level of 9.50%. In Section VI, we discuss PGE's capital structure. Section VII provides our qualifications.

II. PGE's Financial Goals

Q. What is PGE's overall financial goal?

A. PGE's overall goal is to provide adequate capital and liquidity to fund PGE operations at the least cost and least risk to customers. Aligned with this goal is protection against unforeseen negative changes in cash flows and managing daily cash and liquidity needs. For these goals, PGE relies on its revolving lines of credit, long-term debt, and common equity.

Q. Does PGE have additional financial goals?

A. Yes. PGE's overall financial goals include financial performance, counterparty credit risk management, and liquidity management:

- Solid financial performance including:
  - Maintaining investment grade credit ratings;
  - Accessing financial markets at reasonable terms to provide liquidity for operations and capital expenditures;
  - Achieving an actual ROE that is commensurate with the return on equity achieved by a group of utilities with similar characteristics, service territory, and business risks;
  - Maintaining a capital structure of approximately 50% debt and 50% equity over time; and
  - Setting retail prices at a level sufficient to recover prudently incurred costs, including an overall return on utility investment, while taking into account the economic conditions facing PGE's customers.
- Managing wholesale and retail counterparty credit risks to protect our customers and PGE.

- Liquidity Management to meet our obligations and support PGE's operations.

A. Solid Financial Performance

Q. Why is it important for PGE to maintain an investment grade rating?

A. It is important for PGE to maintain an investment grade rating in order to secure financing for both debt and equity at reasonable rates, especially in today's changing financial environment, and to maintain access to wholesale energy markets with the best prices for customers. Without an investment grade rating, PGE's access to financing would be limited, at higher rates, and PGE would have to provide significantly more collateral to its counterparties (and may lose the ability to trade with some counterparties) in the wholesale power and gas markets. This would result in higher costs to PGE's customers.

Q. What does PGE do to maintain its investment grade credit rating?

A. Fundamentally, PGE's credit rating is a function of its financial performance, which is driven by PGE's retail prices and its ability to manage costs. The rating agencies, as well as equity investors, expect companies to meet certain financial performance standards to achieve an investment grade credit rating, as demonstrated in the financial and liquidity ratios that the rating agencies publish. PGE takes various steps to ensure that its financial performance continues to place it within the range of the appropriate financial ratios. PGE accomplishes this through continuous financial management that includes: closely monitoring budgets, minimizing costs to finance operations through the optimal use of revolving credit line, long-term debt, and equity, closely monitoring capital structure; and analyzing counterparty risks and taking appropriate mitigation measures. Using all of these measures helps PGE maintain financial performance levels necessary for investment grade credit ratings.

Q. Financial performance is an important element for the rating agencies. Do rating agencies also consider other factors?

A. Yes. Other factors that rating agencies consider include regulatory and recovery risk, corporate operations and growth, customer and portfolio diversification, and liquidity and other financial measures. We note that in prior years, the rating agencies have been concerned with PGE's earnings volatility due to one-time but significant write-offs, the asymmetric deadband on the Power Cost Adjustment Mechanism (PCAM), and Oregon's regulatory policies, in general. The rating agencies also continue to consider the liabilities associated with long-term Power Purchase Agreements (PPAs), including Qualifying Facility (QF) contracts, as imputed debt on the balance sheet, which increases the company's debt-to-equity ratios. PGE closely monitors the evolving rating agencies' methodologies and annually visits the major rating agencies for presentations and discussions.

Q. Have PGE's bond ratings changed recently?

A. No. PGE's bond ratings have not changed since its last general rate case filing in February 2017 (UE 319). However, PGE did receive two upgrades on its long-term debt from Moody's in the past few years. PGE's long-term debt ratings from Moody's are two notches higher than Standard & Poor's (S&P). We also note that S&P did change the outlook for PGE from Stable to Positive and PGE continues to take steps to meet S&P's ratings criteria for an upgrade. An upgrade from S&P would help lower financing costs for customers through lower pricing on revolving lines of credit and new debt issuance.

Q. How does PGE ensure an optimal long-term cost of capital?

A. PGE aims to issue long-term debt so that debt maturity schedules closely match investment schedules of its capital projects. PGE prefers First Mortgage Bonds (FMBs) as the primary form of debt because they have a lower cost than unsecured alternatives. PGE evaluates private placement market rates, bank term loans, and a delayed draw/forward structure to arrive at the lowest possible financing costs available at the time of PGE's financing need.

Q. How does PGE determine the timing of its financing?

A. PGE forecasts its cash needs, which include capital expenditures, debt maturities, dividends and changes in working capital, and attempts to match its long-term financing proceeds to meet those requirements. In the past, PGE has used a delayed draw for its long-term bonds that allows us to fix the interest rate on the upcoming bond issue, removing interest rate and funding risk**.**

Q. Does PGE's financial performance help PGE to maintain its desired long-term capital structure?

A. Yes. As we stated earlier, PGE's desired long-term capital structure is 50% equity and 50% long-term debt, although it may fluctuate somewhat from year to year. We believe that the 50% equity in PGE's capital structure helps it better withstand difficult situations, such as under-earning due to events outside of PGE's control and continued pressure on equity capitalization ratios due to imputed debt. To maintain this capital structure, PGE uses several techniques and tools as we discussed above. In addition, we require sufficient retail revenues to maintain the required financial ratios and investor expectations for its long-term capital structure. In the future, PGE plans to continue to use equity issuances, stock repurchases, capital expenditure programs, the debt markets, and cash from operations to help maintain PGE's desired capital structure.

B. Manage Customer and Counterparty Credit Risks

Q. Why is it important for PGE to manage customer credit risks?

A. It is important to manage credit risks to limit losses associated with non-payment of customers' bills.

Q. What customer credit risks does PGE face?

A. PGE's energy deliveries and revenues are subject to industry and customer-specific risks and uncertainty, including potential shut down of customer facilities, curtailment of customers' operations, or changes in capacity as a result of economic or specific circumstances. In fact, since the Great Recession in 2008, a number of PGE's large customers have filed for bankruptcy, liquidated businesses, changed ownership or permanently shut down operations, substantially affecting PGE's actual and anticipated energy deliveries. In 2016, operational changes in PGE's solar and metals manufacturing customers caused a further decline in deliveries. In 2017, the paper and solar industries continued to lay off workers and close facilities in PGE's service area. Currently, solar manufacturing customers face uncertainty reflecting changes in US trade policy with regard to solar tariffs. Large retailers are facing mounting competition from online retailers. Large customer-related energy deliveries and revenue risk is asymmetric: through discussions with large customers, PGE is often aware of large expansions and increases to loads in advance to plan for adequate service, but the same notice is not necessarily known or given when a customer's energy deliveries significantly decline.

Q. How does PGE manage its customer credit risk exposure?

A. PGE attempts to minimize the impact of customer defaults and manage customer credit risk by proactively monitoring customer payment habits with PGE and other creditors, as well as reviewing commercial credit reports such as Dun and Bradstreet. If warranted, PGE may collect deposits from high risk customers to minimize loss in the event of a default.

PGE performs credit reviews of its customers, particularly large customers and associated industries. PGE's load forecasters work closely with its Key Customer Managers to gain a better understanding of the business forecasts provided by large customers and their potential consequences on PGE's retail load. After review, PGE determines the appropriate deposit required from a large customer. This deposit typically is up to one-sixth of the annual bill.

Q. How does PGE manage counterparty risk?

A. PGE manages its counterparty risk in wholesale power transactions using the same methods as for large customers. PGE performs credit reviews of wholesale power counterparties, both purchasers and sellers, and then determines the appropriate amount of collateral required from a counterparty based on their credit risk profile. PGE also sets a minimum credit ratings threshold below which it will not trade with a counterparty.

C. Liquidity Management

Q. What is PGE's strategy for liquidity management and related revolving credit facility sizing?

A. PGE's strategy is four-fold:

1. Carry sufficient credit levels to support both operational and power supply needs over a five year, forward-looking time horizon.

2. Achieve a designation of adequate or better from rating agencies (based on Moody's and S&P's interpretation of PGE's liquidity).
3. Fund short-term debt requirements using commercial paper or revolving credit facility loans as appropriate. Issue letters of credit in lieu of cash collateral, if the pricing is advantageous.
4. Manage market exposure related to maturing lines of credit by replacing them one year prior to maturity.

Q. Has PGE separately analyzed its revolving lines of credit requirements?

A. Yes. PGE periodically analyzes its revolver requirements separately for power supply and other operational needs, the sum of which yields the total liquidity requirement for PGE's needs. This approach enables PGE to ensure that its power and gas procurement efforts have enough liquidity to meet collateral requirements, while also maintaining sufficient liquidity for other operations.

Q. When did PGE last perform such an analysis?

A. PGE last analyzed its revolving lines of credit requirements in the fall of 2017.

Q. What were the results of that analysis?

A. Based on the 2017 analysis, PGE determined that its current revolver of $500 million is sufficient to meet its liquidity needs in support of power supply and other operations. PGE will monitor the need to increase the revolver in 2018-2019 based on the outcome of the Integrated Resource Planning (IRP) process and subsequent competitive bidding process.

Q. Did you determine how the results of this analysis would affect PGE's ratings by Moody's and/or S&P?

A. Yes. For Moody's criteria, PGE's liquidity profile would be rated "adequate" in 2018 and 2019. For S&P, PGE would be rated "adequate" in 2018 and 2019 based on their rating criteria. Based on this analysis, PGE determined that its current revolver capacity of $500 million is sufficient at this time to service the company's short term financing needs.

III. Uncertainty in Regulation, Accounting, and Financial Markets

A. Regulation and Financial Markets

Q. What are PGE's current bond ratings?

A. PGE's current bond ratings for secured (first mortgage) long-term debt are A1 from Moody's and A- from S&P. Ratings for unsecured debts are A3 and BBB. PGE's credit ratings, which were recently affirmed, are provided in PGE Exhibit 1001.

Q. You noted above that rating agencies consider a utility commission's regulatory policy when determining a company's rating. Can you provide some additional detail?

A. Yes. Regulatory policy that supports timely recovery of prudent costs is essential to maintaining a stable, investment grade credit rating. Both Moody's and S&P consider regulatory policy a key factor in their determination of a utility's creditworthiness. Moody's places 25% weight on the factor "Regulatory Framework."[3] S&P indicates that "[r]egulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness."[4] Key characteristics in the assessment of regulatory environment for both credit rating firms include the consistency and predictability of Commission decisions, as well as the timely recovery of prudently incurred costs.

[3] With the other three factors and their weights being "Ability to Recover Costs and Earn Returns," 25%, "Diversification," 10%, and "Financial Strength and Liquidity," 40%. "Rating Methodology – Regulated Electric and Gas Utilities." Moody's Investor Service- December 23, 2013.

[4] "Key Credit Factors for the Regulated Utilities Industry." Standard & Poor's- November 19, 2013.

Q. Have financial analysts or rating agencies noted any concerns regarding regulatory outcomes for PGE?

A. Yes. Both Moody's and S&P have expressed some concerns regarding the recovery of PGE's capital costs for the Carty generation plant.[5] They expect that the increased costs for Carty will be recovered either through pending litigation (PGE versus the Carty construction contractor and PGE versus the two sureties who provided a performance bond on the project), or through retail rates.

Q. Do financial analysts have additional concerns regarding regulatory outcomes for PGE?

A. Yes. Sell side analysts have noted that the Public Utility Commission of Oregon (OPUC) has historically allowed ROEs that are slightly below the national average, but they also note that recent settlements have included constructive outcomes such as timely rate recognition of investment, forward-looking test years, revenue decoupling, and a renewable adjustment clause.[6] In the past, ratings agencies have stated concerns regarding the asymmetric nature and size of the deadbands in the PCAM, and it has been an ongoing concern expressed by financial analysts. Sell side analysts have also pointed out PGE's flattening rate base and opposition from intervenors and OPUC Staff during the IRP process regarding PGE's efforts to either buy or build upwards of 175 MW of renewable capacity.[7]

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[5] "Portland General Electric", Credit Opinion, Moody's Investment Service, July 11, 2017.and "Portland General Electric", RatingsDirect, S&P Global Ratings, July 20, 2017.
[6] "POR Maintained Guidance, IRP Pending – Hold" Gabelli & Company- October 31, 2016.
[7] "Consensus estimates remain too high, guidance for 2018 a possible headwind" Goldman Sachs Equity Research, October 15, 2017.

Q. What concerns have financial analysts expressed regarding the PCAM?

A. PGE's asymmetrical deadband is unique. Most electric utilities tend to have a 'pass through' of their power costs if a PCAM is in place, with no deadbands. Thus, it is not unexpected that analysts have expressed concerns about PGE's wide deadband and the asymmetry of benefits allocation, which could result in "meaningful" impacts on PGE's earnings, increasing volatility. Wells Fargo mentions the following risks for PGE: negative regulatory developments; Request for Proposal outcome uncertainty; and risks related to the asymmetrical PCAM (e.g., hydro, plant outages).[8] JPMorgan lists PGE fuel and purchased power recovery mechanism as a source of risk: "any combination of a reduction in hydro conditions or an increase in the price of coal or natural gas could adversely impact POR's near-term earnings."[9] Key Banc views the PCAM as a source of "earnings variability related to fuel price volatility" and has stated that "[a]ny opportunity to make changes to this mechanism to reduce earnings risk around fuel would be viewed positively."[10]

Q. How does increased earnings volatility impact PGE's cost of capital?

A. Financial theory states that, all else equal, increased earnings volatility results in increased uncertainty or risk and thus, a higher return to investors. This is because investors and creditors require greater compensation for owning an investment with more risk. All else equal, a firm with greater earnings volatility will have a higher cost of capital than a firm with more stable earnings. If the current PCAM structure results in a higher level of earnings volatility relative to that faced by comparable firms, then investors' required rate of

[8] "POR CapEX Comes Through on the Q3 Update" – Wells Fargo Equity Research – 28 October 2016.
[9] "U.S. Utilities & Power Outlook" – J.P. Morgan – 16 December 2016.
[10] "Utilities – ALERT: Edison Electric Institute" – Key Banc Capital Markets, Inc. 8 November, 2016.

return for PGE will be higher as well. As a result, investors will demand a higher return to hold PGE's debt or common stock, which will increase the cost to finance PGE activities.

B. Update of Financial and Accounting Regulation Changes

Q. How have financial sector regulations changed?

A. Following the financial crisis, policymakers and regulators have sought to impose tougher rules and standards on banks in hopes of preventing future systemic crises. Regulatory efforts have been primarily focused in the following four areas: higher capital requirements (including higher minimum ratios and higher quality capital); new liquidity standards (new ratios and requirement for higher quality liquid assets); assigning higher capital requirements and increasing supervision for the largest, Systemically Important Banks; and adopting national initiatives (Dodd-Frank and Volker rules).

Q. How did commercial banks meet these new requirements?

A. First, the banks began tightening lending standards during 2012, making it more difficult for firms to access credit, potentially increasing firms' costs to obtain credit. Second, banks were forced to participate in the liquidity scenarios outlined by central banks around the world, encouraging many to keep more reserves on hand than they had historically. One additional result is that U.S. banks have significant excess reserves at the Federal Reserve Bank (Fed),[11] leaving less available for lending.

Q. Will these new requirements affect PGE's ability to access funds?

A. PGE has yet to see a significant impact on borrowing costs due to these requirements. In 2015, there was some financial stress passed through to PGE and other utilities as banks complied with the Basel III/Basel IV regulation (full compliance is required by 2019).

[11] http://research.stlouisfed.org/fred2/series/EXCSRESNS.

Even though most large US banks have now passed the Federal stress tests for capital requirements, many banks have chosen to be more particular when lending funds, and therefore, the availability of credit has tightened for certain entities.

Q. What challenges does PGE face in connection to imputed debt?

A. As previously discussed, PGE faces significant risks and uncertainties connected with imputed debt from purchased power contracts: S&P "imputes" additional debt to PGE's capital structure based on the payments under long-term PPAs. S&P believes that because of these quasi-debt instruments, an adjustment must be made to the capital structure to reflect the additional leverage of PPAs. As PGE acquires additional long-term capacity contracts and QF contracts, this imputed debt adjustment could result in increases in the debt ratio large enough to create a quantitative trigger for potential ratings downgrades. A ratings downgrade by S&P from PGE's current rating level could result in higher interest rates on debt issuances, an inability to attract equity capital at a reasonable price, and additional collateral postings for power supply operations.

Q. What challenges does PGE face in connection to FASB[12] pronouncements?

A. Accounting Standards Codification (ASC) 810 Consolidation of Variable Interest Entities (VIE), provides guidance for determining the financial reporting for entities over which control is attained by means other than through voting rights. Under ASC 810, consolidation is based on the power to direct significant activities of the VIE and the obligation to absorb losses that are significant to the VIE. The entity with the power to direct significant activities and the obligation to absorb significant losses becomes the "primary beneficiary" of the VIE and, in turn, is required to consolidate the financial

[12] Financial Accounting Standards Board (FASB).

statement of the VIE for financial reporting to the Securities and Exchange Commission (SEC). ASC 810 requires consolidated financial statements to reflect total assets under control and total liabilities for which an entity is responsible.

Under ASC 810, although it is not involved in the creation of these entities and has no equity or debt invested, PGE may be required to reflect the total assets, liabilities, and non-controlling interests of its PPA counterparties on PGE's balance sheet on an ongoing basis when reporting its financial position on a consolidated basis. The counter-party entities are expected to be highly debt leveraged and consolidating their capital structure will likely increase PGE's debt-to-equity capital structure. This high debt leverage will impact PGE's creditworthiness, as the increase to PGE's debt-to-equity percentage increases financial risk. To support PGE's creditworthiness and realign its capital structure, an increase to PGE's common equity could be necessary to offset the impact of the additional debt, consolidated under ASC 810.

Q. Has the FASB revised or added Accounting Standards that could impact PGE?

A. Yes. In February 2016, ASC 842 Leases was updated by the FASB. The new standard requires operating leases to be recorded on a company's balance sheet as a right of use asset with a corresponding lease liability. On the income statement, capital lease assets will be amortized and recorded within applicable depreciation and amortization periods, and the minimum lease payments will be split between principal and implied interest, which will be recorded as interest expense. Operating leases will record amortization and interest expense as one straight line value within operating expense on the income statement. PGE is in the process of quantifying the impacts of the new lease standard and plans to adopt the standard no later than its effective date of January 1, 2019. In light of our earlier discussion on imputed debt, PGE continues to discuss with S&P and Moody's their expected treatment of these changes for ratings purposes, but nothing definitive is available yet.

C. Macroeconomic Uncertainty

Q. One factor that can certainly affect bond ratings is the economy, as earnings are partially driven by economic growth. Can you provide a brief overview of recent and expected market conditions?

A. Yes. The US economy has been growing at an accelerated rate, 3.2% in the third quarter of 2017,[13] and the Fed raised the federal-funds interest rates by a quarter-point three times in 2017. At the December 13, 2017 meeting of the Fed, the Federal Open Market Committee (FOMC) said it would increase its benchmark federal-funds rate by a quarter percentage point to a range between 1.25% and 1.5%, the fifth such increase in the past two years. Officials forecasted three more quarter-point rate increases for 2018, and two more quarter-point increases each in 2019 and 2020.[14] The recent tax reform legislation will likely provide more economic stimulus, which may cause the FOMC to accelerate the 2018 increases in federal-funds rates.

The U.S. economy has become more integrated with the rest of the world's economies as well. Because of this, major developments in other parts of the world can affect the U.S. economy and its interest rates. There are numerous areas of concern and risk in the world economy today such as Greece, Italy, the United Kingdom (UK), Venezuela, and Puerto Rico.

Greece's national credit rating remains at junk status (CCC) as they struggled to complete the third restructuring of their sovereign debt in November of 2017. They are faced with

[13] US Bureau of Economic Analysis: https://www.bea.gov/newsreleases/glance.htm.
[14] Fed Raises Rates, Sticks to Forecast for 2018 Increases, Wall Street Journal, 12/14/2017.

additional austerity covenants, which do not sit well with the populace. The Greek economy is growing at a slow 1.0% and could return to deficit in 2018, Greek unemployment at 20.6% is the highest in Europe, and the country's Debt/Gross Domestic Product (GDP) ratio remains the highest in the world at 180%. The Greek government faces political difficulties in implementing debt refinance covenants and popular sentiment is divided on submitting to the austerity measures and remaining within the Eurozone.[15]

The Italian government faces elevated social tensions that have led to widespread political unrest. Like Greece, they are highly leveraged with Debt/GDP at 133% - the fourth highest globally.[16] They have a stagnant economy, and a very fragile banking system, which continues to have to deal with legacy toxic debt holdings and insufficient capital reserve accounts. Failure of Italy's banks could result in negative financial consequences across Europe with potential effects on global markets as well.

Britain's economy has been hit hard by increasing inflation in the wake of the Brexit vote in 2016, curtailing consumer spending and driving up prices. The UK growth outlook is also souring with post-Brexit economic forecasts to slump to 1.1% in 2019, making it one of the slowest growing economies after Italy's forecasted 1% expansion.[17]

Venezuela is racked by political, social, and economic crises. The International Monetary Fund estimated that Venezuela's GDP will fall 12% in 2017 after contracting 16.5% in 2016, while inflation in 2018 could be 2,000%.[18]

[15] The Economist Intelligence unit, Greece, September 2017.
[16] DEUTSCHE BANK "Italy's 3 big problems could trigger the next financial crisis – and bring the euro down with it" September 20, 2017. http://www.businessinsider.com/italy-financial-crisis-deutsche-bank-2017-9.
[17] "Eurozone Growth Set to Accelerate as Threats Subside; Bloc still faces labor, wage and inflationary pressures compounded by Brexit risks:" Wall Street Journal, November 9, 2017.
[18] Venezuelan Debt Crisis will be Huge and Devilishly complex; with the country racked by crises, any restructuring of Venezuela's debt will be a colossal undertaking, WSJ, November 3, 2017.

Puerto Rico has struggled with a decade of economic stagnation and owes investors over $70 billion. In the summer of 2017, Congress approved a bankruptcy-like framework for the island to restructure its debts. A federally appointed control board in March approved a plan under which bondholders would be paid about a quarter of what they are owed over the next 10 years. Under the plan, the Commonwealth also had to cut government spending. Hurricane Maria in October 2017 devastated the island and increased uncertainty that the bonds would be repaid.

There is also uncertainty surrounding long-term economic effects of the recent federal tax reform and the related $1.4 trillion increase in the federal deficit. U.S. government bonds weakened recently as investors were analyzing the potential effect of the passage of the tax bill. After the bill passed the Senate in early December 2017, the yield on the benchmark 10-year U.S. Treasury note rose for the fourth time in five days to 2.379% from 2.363%.[19] Bond prices slipped after the Senate passed revisions to the bill and moved closer to pushing through $1.4 trillion in tax cuts. Some analysts and investors believe that lower corporate tax rates could lift company earnings and boost growth, adding to the appeal of riskier assets. Investors also said that the tax overhaul could help push wages higher, fueling inflation, and eroding the purchasing power of bonds' fixed payments. The new legislation may require additional government borrowing, which could push yields higher as the supply of bonds increases. Many investors have said that the tax cut plan could make the Fed more likely to increase the pace of its projected interest rate increases in 2018 and 2019.

[19] "US Government Bond Yields Rise on Tax Plan Progress- The tax overhaul plan is adding to the appetite for riskier investments" Wall Street Journal, December 4, 2017.

IV. Cost of Long-Term Debt

Q. What is PGE's cost of long-term debt?

A. PGE's cost of long-term debt in 2019 is expected to be 5.123%. PGE Exhibit 1002 presents the amount and the effective cost of PGE's outstanding long-term debt for the test year. This includes existing bond issuances as of January 15, 2018, as well as bond issuances and retirements expected in 2018 and 2019.

Q. How did you calculate the cost of long-term debt for 2017?

A. We started with the debt costs approved in OPUC Order No. 17-511 and made applicable adjustments. When calculating the amount of debt outstanding, the full amount and cost for each issuance of outstanding debt at year end is included. We then multiply the amount outstanding by the effective interest rate for each bond issuance. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issuance, including all unamortized call premiums and issuance expenses for debt issuances replaced before maturity with less expensive financings. Table 2 below summarizes PGE's cost of long-term debt for the 2019 test year.

Table 2

PGE's Cost of Long-Term Debt ($000)

	2019 Forecast	UE 319 Order No. 17-511	Difference
Principal Amount	$2,378,067	$ 2,436,400	$ (58,333)
Annual Interest Cost	$121,828	$ 126,766	$ (4,937)
Effective Interest Rate	**5.123%**	**5.203%**	**(0.08)%**

Note: UE 319 Principal Amount reflects downward principal revisions as of October 27, 2017.

Q. What future debt issuances did you include in your analysis?

A. At this time, PGE does not anticipate the need to issue long-term debt in 2018. However, PGE does expect to issue two, 30-year tranches of FMB's totaling $300 million in 2019, which we included in our analysis.

Q. What is the expected term, coupon rate, and issuance cost for the bonds to be issued in 2019?

A. The two 30-year tranches of FMBs have an estimated combined coupon rate of 5.005% which will replace $300 million of maturing notes in April of 2019. The first tranche is expected to be issued in April 2019 and the second tranche is expected to be issued late in 2019. We will provide an update to PGE's cost of long-term debt in our rebuttal testimony, which will include any changes in long-term debt.

Q. How are the estimated coupon rates and issuance costs derived by PGE?

A. The rates are based on an indicative new issuance pricing analysis, which includes a current estimated credit spread provided by a subset of PGE's investment banks and a forecast of treasury rates from *Global Insight*.

Q. Is there any long-term PGE debt maturing in 2018 or 2019?

A. Yes. As noted above, PGE has $300 million of term loans maturing in April 2019. There are no scheduled maturities in 2018.

V. Cost of Equity

Q. Please summarize your approach to estimating PGE's ROE.

A. In December 2017, the OPUC authorized a 9.5% ROE for PGE through Order No. 17-511 in UE 319. Our analysis in this case verifies the reasonableness of maintaining this ROE. We estimated the cost of equity for PGE using the OPUC preferred Discounted Cash Flow (DCF) method. We also used the Capital Asset Pricing Model (CAPM) as well as a Risk Premium model. In determining the cost of equity, we relied on the same methods and inputs as in UE 319 to the degree possible.[20] The cost of equity estimates are derived as of November 30, 2017, using 2019 forecasted interest rates and new income tax rates from recent tax reform legislation. We summarize the results in Table 3 below.[21]

Table 3:
Summary of ROE Estimates for PGE[22]

	Range of Estimates	Midpoint
DCF Models	8.6% - 11.1%%	9.8%
Risk Premium Model	10.2% - 10.3%	10.2%
Other Tests	9.2% - 10.4%	9.8%
Range	8.6% - 11.1%	9.8%
Midpoint* / Average*	9.8%	9.9%

**Ignores the ROEs based on historical GDP growth.*

Q. How do these results support your recommendation for maintaining PGE's current 9.5% ROE?

A. The results range from 8.6% to 11.14% with a midpoint of 9.8%. At the same time, recently allowed ROEs average 9.7%, so the requested 9.5% is not only lower than the midpoint, but

[20] Because companies enter into merger or acquisition arrangements and because PG&E recently cut dividends, the samples differ.
[21] The OPUC has, in the past, given no weight to the CAPM (Order No. 01-777, p. 32). Therefore, the CAPM is used as a check on the other estimates rather than a primary method in this matter.
[22] Data cited in Table 3 use all sample companies.

also lower than recently allowed ROEs for integrated electric utilities.[23] Therefore, a 9.5% ROE is conservative and near the low end of the estimation results.

We understand that the Commission in the past has relied primarily on the DCF model and, in particular, the multi-stage DCF model, where the low end is estimated at 8.6%. However, this figure is downward biased as: (1) it relies on a very low GDP growth rate that is well below what has been experienced historically or during the first three quarters of 2017; and (2) the estimate is well below the results from other estimation methods. To assess the reasonableness of the multi-stage DCF and the forecasted GDP growth rate, we also estimated the multi-stage DCF model using the average GDP growth rate from 1990 to today (ROE of 9.0%) and from 1947 to today (ROE of 11.1%).[24]

Q. What economic factors currently impact the ROE?

A. As we explained above, interest rates and especially government bond yields have been low, but have started to increase. The Federal Reserve raised the target for the federal-funds rate on December 14, 2017 and signaled that further increases are likely.[25] All else equal, increasing interest rates makes it likely that investors' expected ROE will increase going forward. In addition, the tax reform legislation, as well as international events such as those discussed above, creates uncertainty for investors, which may impact the ROE.[26]

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[23] We note that the average allowed ROE for 2017 was approximately 9.7%. Source: Authorized ROE data from SNL Financial as of 11/30/2017.

[24] Growth data from Federal Reserve of St. Louse, "Gross Domestic Product" Downloaded January 5, 2018 and Bureau of Economic Analysis, "U.S. Economy at a Glance," January 2018.

[25] The Federal Reserve increased the target for the federal funds rate from 1 to 1¼ to 1 ¼ to 1½% on December 13, 2017. Source: https://www.forbes.com/sites/laurengensler/2017/12/13/federal-reserve-raises-interest-rates-for-third-time-in-2017/#695020107a53.

[26] For example, Moody's changed the outlook on 25 utilities on negative outlook on January 19, 2018. Source: "Moody's changes outlook on 25 US regulated utilities primarily impacted by tax reform."

Q. How did you estimate PGE's ROE?

A. To assess the cost of equity for PGE, a sample of integrated electric utilities is selected from Value Line's universe of electric utilities. The sample companies are selected to be comparable to PGE, so it includes electric utilities that (i) have more than 50% regulated assets and (ii) own generation. In addition, the companies are screened based on financial criteria such as credit ratings and on data availability. For each company, we then estimated the cost of equity using standard methods including two versions of the DCF model, the risk premium model, a review of recently allowed ROE, and as a test, two versions of CAPM. The characteristics of the 22 sample companies are displayed below in Table 4.[27]

[27] Compared to the sample in UE 319, Sempra was eliminated due to its planned acquisition of Oncor and Vectren was eliminated due to the announcement that it is considering the takeover interests in the company. Dominion and Scana were eliminated due to their announced merger. PG&E was eliminated as it has announced a dividend cut. Duke Energy was added as its acquisition is well in the past and PNM's was added as its lower credit rating is more than five years old.

Table 4:
Characteristics of Sample Companies

Company	CAPM Subsample	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2017 Q3 (USD million)	Betas	S&P Credit Rating (2017)	Long Term Growth Est.
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE			$1,423	M	$3,963	0.75	BBB−	4.9%
Alliant Energy	*	*	$3,323	R	$9,787	0.70	A-	6.6%
Amer. Elec. Power	*	*	$15,405	R	$35,328	0.65	A-	3.9%
Ameren Corp.	*	*	$6,131	R	$14,327	0.65	BBB−	6.6%
CenterPoint Energy			$9,057	M	$12,812	0.90	A-	6.9%
CMS Energy Corp.	*	*	$6,445	R	$13,310	0.65	BBB−	7.2%
Consol. Edison	*	*	$11,779	R	$25,682	0.50	A-	3.1%
DTE Energy	*	*	$12,210	R	$19,692	0.00	BBB−	4.7%
Duke Energy	*	*	$22,582	R	$60,010	0.60	A-	3.3%
Edison Int'l	*	*	$11,984	R	$25,912	0.65	BBB−	5.7%
El Paso Electric	*	*	$909	R	$2,230	0.80	BBB	5.2%
Entergy Corp.	*	*	$11,099	R	$13,998	0.65	BBB−	-3.2%
IDACORP Inc.	*	*	$1,337	R	$4,490	0.70	BBB	4.1%
MGE Energy			$562	M	$2,265	0.75	AA-	7.9%
OGE Energy	*	*	$2,290	R	$7,219	0.95	A-	5.2%
Otter Tail Corp.	*	*	$839	R	$1,703	0.90	BBB	7.5%
Pinnacle West Capital	*	*	$3,545	R	$9,757	0.70	A-	5.5%
PNM Resources	*	*	$1,449	R	$3,317	0.00	BBB−	6.6%
Portland General	*	*	$2,018	R	$4,140	0.70	BBB	4.9%
PPL Corp.	*	*	$7,353	R	$26,705	0.70	A-	2.5%
Public Serv. Enterprise			$9,078	M	$23,230	0.70	BBB−	1.8%
Xcel Energy Inc.	*	*	$11,403	R	$24,546	0.60	A-	5.5%
Average			$6,919		$15,656	0.65	BBB−	4.8%
Subsample Average			$7,339		$16,786	0.62	BBB−	4.7%

Companies marked with a * have more than 80% of their assets subject to regulation.

Q. What steps do you take to ensure that the ROEs for the sample are representative?

A. As the cost of equity capital for a company depends on its financial leverage, the estimated cost of equity figures for the sample were converted to an estimate for PGE using its 50-50 capital structure. We do this to ensure consistency between the capital structure used to derive the cost of equity estimates and PGE's regulatory capital structure, and also evaluate critical risk factors that may differ between PGE and the sample. We also looked to PGE's level of risk relative to the sample to assess where in the estimated range PGE reasonably falls. Two risk factors are somewhat unique to PGE: (i) PGE is a smaller size utility than the average sample companies and (ii) Oregon and the City of Portland have climate policy initiatives to reduce the emission of carbon dioxide (CO_2), These factors may impact PGE's generation fleet and consequently PGE's risk due to (i) a combination of a reduction in sales volumes and the asymmetric PCAM or (ii) in a worst case scenario, inability to fully recover cost of investments.

Q. Having selected a comparable sample, what steps do you take to estimate the cost of equity capital?

A. As noted above, the cost of capital estimation process employs three general methodologies: DCF, CAPM, and risk premium models. All methods are commonly used in US state regulatory proceedings and have been presented to the Commission previously by PGE. For the DCF estimates, we present two models: the standard Gordon growth model (or the single-stage DCF) and a three-stage DCF model. We implement the three-stage DCF model using three different long-term growth rates: the consensus Blue Chip forecast; an average of the estimate from Office of Management and Budget (OMB) and Blue Chip (which is no different from the Blue Chip); and two historical growth rates, which are used as checks. Further, a version of the risk premium method (i.e., a regression analysis of allowed return on bond rates) is used to estimate the ROE. Finally, two versions of the CAPM were implemented as a check on the results: the traditional CAPM and a version of the Empirical CAPM.[28] Because the cost of equity cannot be measured precisely, it is important to consider more than one method. Further, each method has its strengths and weaknesses, which may be more or less prevalent at any given time. It is, therefore, necessary to evaluate the estimated cost of equity in light of the prevalent market conditions and the relative strengths and weaknesses of the model to take these factors into account.

[28] The CAPM is a commonly used cost of capital estimation model in corporate finance and Dr. Villadsen usually includes it among her methods. As noted above, however, the OPUC has historically not relied upon the CAPM, so it is used as a check on other capital estimation model results in this proceeding.

A. The DCF Based Estimates

Q. Please describe the DCF approach to estimating the cost of equity.

A. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The standard DCF application goes on to make the assumption that the growth rate remains constant forever, which simplifies the standard formula, so that it can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by the formula:

$$P = \frac{D_1}{(r-g)}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "r" are the market price and the cost of capital, as before.

Q. Are there other DCF models?

A. Yes. There are many alternatives, notably, (i) multi-stage models and (ii) models that use cash flow rather than dividends or combinations of (i) and (ii).[29] One such alternative expands the model to three stages.[30] In the multi-stage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.

[29] The Surface Transportation Board uses a cash flow based model with three stages. See, for example, Surface Transportation Board, "Ex Parte No. 664 (Sub-No. 1)," Issued January 23, 2009. Confirmed in EP 664 (Sub-No. 2), issued October 31, 2016.

[30] Note that because investors are interested in cash flow, it is technically important to include all cash flow that is distributed to shareholders. Notably, many companies distribute cash through share buybacks in addition to dividends and therefore, we would include this type of distribution. However, among the comparable companies only El Paso Electric has non-trivial share buybacks and including the amount would not affect the results. Therefore, we ignore this aspect for this proceeding.

Q. What inputs do you use for your DCF model?

A. Investment analysts' forecasted earnings growth rates from Bloomberg and from Value Line for the companies in the electric sample are used as the growth forecast. For the long-term growth rate for the final, constant-growth stage of the multi-stage DCF estimates, we use several estimates: (i) the most recent long-run GDP growth forecast from Blue Chip Economic Indicators (ii) the average of the OMB and Blue Chip long-term estimate, and (iii) two historical GDP growth rates are used as checks.[31]

Q. What are your DCF estimates?

A. Looking at the full sample, the ROE estimate is 10.2% for the Gordon (single-stage) DCF model and 8.6 to 11.1% for the multi-stage model. Table 5 below summarizes the results from the DCF models.[32]

Table 5: DCF Estimates on the Cost of Equity

	GDP growth from Blue chip	1990-2016 historical GDP	1947-2016 historical GDP
Full Sample			
Simple	10.2%	10.2%	10.2%
Multi-Stage	8.6%	9.0%	11.1%
Regulated Subsample			
Simple	9.7%	9.7%	9.7%
Multi-Stage	8.5%	8.8%	10.9%

Q. Do you have any comments on the DCF estimates?

A. Yes. The multi-stage DCF estimates relying on the Blue Chip Growth Forecast may well be downward biased as they rely on a historically low GDP growth rate. This is shown by

[31] *Blue Chip Economic Indicators*, October 10, 2017.
[32] For details, see PGE Exhibit 1003.

using two historical periods of GDP growth, and it is worth noting that recent GDP growth in the US has exceeded the Blue Chip forecast.

B. Risk Premium and CAPM

Q. Do you estimate the cost of equity that results from a risk premium analysis?

A. Yes, the risk premium is estimated using a statistical regression approach. Specifically, the statistical relationship between the allowed ROE for electric utilities and the 20-year government bond rate is calculated using quarterly data. This results in an estimated ROE of 10.4% to 10.5% for 2019.

Q. Please explain the implementation and data underlying your risk premium analysis.

A. Using quarterly data from Regulatory Research Associates from Q1 1990 to Q3 2017,[33] the following is estimated:

$$\text{Risk Premium} = A_0 + (A_1 \times \text{Treasury Bond Yield})$$

The equation is estimated using ordinary least squares and the parameters are statistically significant at the 5% level (details are in PGE Exhibit 1004). Using this approach, the risk premium coefficient (A_1 = -0.56%) and a constant (A_0 = 8.48) is determined. The risk premium then determines the cost of equity as:

$$\text{Cost of Equity} = \text{Forecasted Bond Yield} + \text{Risk Premium}$$

The forecasted 20-year yield for 2019 is 3.90% if the currently elevated yield spread is not taken into account and 4.10% if the elevated yield spread is assumed to remain.[34] Using

[33] SNL Financial as of October 31, 2017.
[34] *Blue Chip Economic Indicators Forecast*, October 2017.

these two forecasts for the risk-free rate, we obtain cost of equity estimates of 10.2% and 10.3%, respectively.

Q. Please summarize your CAPM model.

A. The CAPM determines the cost of equity as follows:

$$r_S = r_f + \beta_S \times MRP$$

where r_s is the cost of capital for investment *S*; r_f is the risk-free rate; β_S is the beta risk measure for investment *S*; and *MRP* is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. The model is estimated using Value Line betas, the risk-free rate that Blue Chip forecasts for 2019 plus 20 basis points to account for an elevation in yield spread (as in the risk-premium analyses above), and the historical MRP for the period 1926-2016 as reported by the 2017 Duff & Phelps Valuation Handbook.[35] The model was also implemented using the forecasted yield for 2019 and an elevated MRP of 7.4%, which is consistent with recent Bloomberg forecasts for the MRP. Finally, we implemented two variations of the model that relies on the empirical observation that the intercept, α, in the model is higher than in the theoretical CAPM, but the slope, β, is lower. The CAPM and the empirical CAPM results in cost of equity estimates in the range of 9.5% to 10.4% for the full sample and 9.3% to 10.2% for the subsample, which confirms that PGE's requested ROE of 9.5% is conservative. The details of this model are in PGE Exhibit 1005.

[35] *Blue Chip Economic Indicators*, October 2017; Duff & Phelps, 2017 Valuation Handbook, Guide to Cost of Capital, page 3-24.

Q. Based on the analysis above, please summarize the evidence regarding PGE's recommended ROE.

A. The evidence demonstrates that a 9.5% ROE remains a conservative, but reasonable ROE for PGE. Interest rates are increasing and, combined with the other factors we discuss above, PGE's cost of equity can be expected to rise in the 2019 test period. In this environment, maintaining PGE's authorized ROE and capital structure should be a non-controversial resolution to cost of capital issues in this case.

VI. Capital Structure

Q. How did you determine the appropriate capital structure for 2019?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2018. Additionally, we considered several factors, including: 1) PGE's need to maintain its financial strength; 2) flexibility and adequate liquidity; 3) its ability to maintain reliable and economical access to the capital markets; 4) minimizing the cost of capital to customers and shareholders; and 5) Commission Order No. 17-511 in Docket UE 319. We also considered PGE's desire to maintain a capital structure consisting of 50% long-term debt and 50% equity.

Q. Does PGE expect to issue common equity in 2019?

A. No. At this time PGE does not anticipate additional equity issuances, but we will provide an update if financing plans change.

Q. Are you seeking a different capital structure than in docket UE 319?

A. No. In UE 319, the OPUC adopted a settlement among the parties that reaffirmed PGE's regulated capital structure at 50% equity and 50% debt even though PGE's expected regulated capital structure contained more equity. PGE's long-term goal continues to be to maintain its capital structure at 50% equity and 50% debt; however, the equity ratio fluctuates around the 50% target level, due to the timing and size of debt and equity issuances.

Q. Why does PGE intend to maintain 50% equity in its capital structure?

A. It is the optimal debt-to-equity ratio for PGE because it offers a balance between the ideal debt-to-equity range and reduces PGE's cost of capital. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs, which directly impacts customer prices. We believe that the 50% equity in PGE's capital structure helps it better withstand difficult situations, such as under-earning due to events outside of PGE's control. In addition, the equity portion helps offset the leverage and risk that PGE encounters, in part, as it has finished its large capital expenditure program. It is also required to help offset the leverage imputed by the rating agencies due to purchased power. Additionally, PGE faces risks in today's banking environment because of its relatively small size, and it must maintain a solid capital structure and financial flexibility to help manage customer costs and provide shareholder value.

Q. Aside from the risks discussed above, what other types of significant risks does PGE encounter today?

A. PGE encounters a variety of risks including:

- Hydro and wind availability and weather changes create risk for PGE in several ways, including: lower than average stream flows; lower than average wind flows and the timing of it; and volatility in electricity usage because of sudden, unexpected weather changes and severe storms. This weather risk is not mitigated by PGE's decoupling mechanism. These risks can potentially force PGE to purchase more spot energy, when the markets may be tight. The costs resulting from these purchases could be greater than what is included in customer prices.
- Regional economic weakness can adversely affect PGE's revenues. Weakness in Oregon's economy can lead to a decline in electricity usage as customers become more conservative. This can negatively impact PGE's revenues, thereby reducing PGE's profits, which negatively affect PGE's retained earnings and returns to

investors. Lower retained earnings affect our ability to reinvest in the business. Oregon's economy was especially hard-hit during the recession and financial crisis of 2008 and was slow to recover compared to other regions of the nation. The state's new minimum wage law, passed during the 2016 legislative session, will also have a negative impact on job growth. While the impact may be small when compared to the size of the Oregon economy, it is estimated that there will be approximately 40,000 fewer jobs in the state in 2025 than would have been the case if the legislation did not pass.[36]

- Uncertainty regarding financial and business operations contingencies, as noted in PGE's SEC annual 10-K and quarterly 10-Q filings.[37] PGE could be vulnerable to cyber security and physical assets attacks. The electric industry is going through accelerated technological changes, which can make a basic premise of the current business model (economies of scales gained from central generation facilities) obsolete.
- Uncertain federal and state energy policy from legislative or regulatory efforts to reduce greenhouse gas emissions and water discharges from thermal plants could lead to increased capital and operating costs. Operating changes required of PGE in order to comply with existing and new laws related to fish and wildlife also could materially increase PGE costs.

[36] Oregon Economic and Revenue Forecast, December, 2017, page 13; http://www.oregon.gov/das/OEA/Documents/forecast1217.pdf.
[37] http://investors.portlandgeneral.com/sec.cfm Starting with page 114,Note 17- 2016 SEC Form 10-K. http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-17-53&CIK=784977. Starting with page 23, Note 7- the most recent 10/27/17 PGE SEC Form 10-Q.

Q. Do the financial markets agree that these are risks for PGE?

A. Yes. Recent reports from various equity analysts include at least one of the risks listed above. We have included the most recent reports from Wells Fargo and Ladenburg in our work papers.

Q. Can PGE mitigate these risks?

A. PGE can manage some of these risks, but not others. For risks that PGE can manage, PGE develops management capabilities and core competencies, as well as establishes strong processes and procedures to mitigate those risks. PGE is proactively implementing programs that will better prepare it for the operational impacts of adverse events. For example, improving the ability to recover from catastrophic events remains a key strategic focus of PGE. PGE's Department of Business Continuity and Emergency Management has developed formal recovery plans to address disasters and implement emergency management procedures. PGE is also taking measures to address cyber security risks by increasing Information Technology security staff and evaluating process improvements for detection and prevention of cyber-attacks. Another risk category is PGE's fuel supply. PGE continues to develop backup plans for fueling its power plants in the event of extended outages of natural gas pipelines or coal supply. PGE is looking at gas dispatch modeling and performing cost-benefit analysis of re-establishing the ability of gas plants to run on oil if pipeline interruptions occur. PGE is also moving forward with storage solutions and has an estimated online date of January 1, 2019 for the North Mist expansion storage facility[38] to provide long-term no-notice underground natural gas storage to serve the Beaver and Port Westward natural gas-fired generating plants.

[38] See PGE Exhibit 300, Section III, part C.

We note, however, that there are risks that PGE cannot manage including those associated with the government or regulatory framework. For these types of risk, PGE ensures that it is prepared and capable of responding to them to the best of its ability and PGE continues to actively participate in the legislative and regulatory arenas.

Q. Could the risks addressed above alter the cost of capital you request?

A. Yes. If these risks result in financial distress to PGE and/or its peers, the cost of long-term debt and the cost of equity will increase, with a resulting long-term cost impact on customers through increased borrowing costs and possibly a ratings downgrade.

VII. Qualifications

Q. Mr. Hager, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from the University of Santa Clara 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 and 2010-2018, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

Locally, I have been on the Board of Directors for Advantis Credit Union since 2007, serving previously on the Audit Committee. I also serve on the board and as treasurer for the Portland Chapter of the American Association of Individual Investors (AAII). 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.

Q. Mr. Liddle, please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration with a finance emphasis from the University of Oregon in 2004 and a Master of Business Administration degree from Portland State University in 2009. I have been employed at PGE since 2005, beginning as an analyst in PGE's Corporate Finance Department. I have worked in PGE's Investor Relations Department and spent approximately seven years working in

PGE's Rates and Regulatory Affairs Department. I then managed PGE's forecasting team including financial and load forecasting, and economic analysis. My current position is Assistant Treasurer and Manager of Corporate Finance & Investor Relations.

Q. Dr. Villadsen, please state your educational background and experience.

A. I hold a Ph.D. from Yale University's School of Management with a concentration in accounting. I have a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, I was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where I taught financial and cost accounting. I have also taught graduate classes in econometrics and quantitative methods. I have worked as a consultant for Risoe National Laboratories in Denmark.

My work concentrates in the areas of regulatory finance and accounting. My recent work has focused on accounting issues, damages, cost of capital and regulatory finance. In the regulatory finance area, I have testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and decoupling on cost of capital and earnings. I have been involved in accounting disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. I have estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. I have filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions. My testimonies and expert reports pertain to accounting issues, damages, discount rates and cost of capital for regulated entities. A detailed vita of my qualifications is included in Exhibit 1006.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1001C	Standard & Poor's and Moody's Investors Service Credit Ratings
1002	Cost of Long-Term Debt
1003	Discounted Cash Flow Model
1004	Risk Premium Model
1005	Capital Asset Pricing Model
1006	Villadsen Vita

Exhibit 1001C

Protected Information Subject to Protective Order 18-047

Standard & Poor's and Moody's Investors Service Credit Ratings

	S&P	Rating Date	Moody's	Rating Date
Senior Secured Debt	A-	7/20/2017	A1	7/11/2017
Senior Unsecured	BBB	7/20/2017	A3	7/11/2017
Short-term/ Commercial Paper	A-2	7/20/2017	P-2	7/11/2017

"Credit Opinion: Portland General Electric Company" July 20, 2017. Standard & Poor's
"Credit Opinion: Portland General Electric Company" July 11, 2017. Moody's Investors Service

SAMPLE CAPITAL STRUCTURE AND DCF MODEL

Table No. BV-ELEC-2

Classification of Companies by Assets

Company	Company Category
ALLETE	M
Alliant Energy	R
Amer. Elec. Power	R
Ameren Corp.	R
CenterPoint Energy	M
CMS Energy Corp.	R
Consol. Edison	R
DTE Energy	M
Duke Energy	R
Edison Int'l	R
El Paso Electric	R
Entergy Corp.	R
IDACORP Inc.	R
MGE Energy	M
OGE Energy	R
Otter Tail Corp.	R
Pinnacle West Capital	R
PNM Resources	R
Portland General	R
PPL Corp.	R
Public Serv. Enterprise	M
Xcel Energy Inc.	R

Sources and Notes:
Percent regulated categories and company data are based on Edison Electric Institute: "Q1 2017 - Stock Performance".
R = Regulated (greater than 80 percent of total assets are regulated).
M = Mostly Regulated (50 to 80 percent of total assets are regulated).
D = Diversified (less than 50 percent of total assets are regulated).

U.S. Electric Sample

Company	CAPM Subsample	DCF Subsample	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2017 Q3 (USD million)	Betas	S&P Credit Rating (2017)	Long Term Growth Est.
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE			$1,423	M	$3,963	0.75	BBB+	4.9%
Alliant Energy	*	*	$3,323	R	$9,787	0.70	A-	6.6%
Amer. Elec. Power	*	*	$15,405	R	$35,328	0.65	A-	3.9%
Ameren Corp.	*	*	$6,131	R	$14,327	0.65	BBB+	6.6%
CenterPoint Energy			$9,057	M	$12,812	0.90	A-	6.9%
CMS Energy Corp.	*	*	$6,445	R	$13,310	0.65	BBB+	7.2%
Consol. Edison	*	*	$11,779	R	$25,682	0.50	A-	3.1%
DTE Energy	*	*	$12,210	M	$19,692	0.00	BBB+	4.7%
Duke Energy	*	*	$22,582	R	$60,010	0.60	A-	3.3%
Edison Int'l	*	*	$11,984	R	$25,912	0.65	BBB+	5.7%
El Paso Electric	*	*	$909	R	$2,230	0.80	BBB	5.2%
Entergy Corp.	*	*	$11,099	R	$13,998	0.65	BBB+	-3.2%
IDACORP Inc.	*	*	$1,337	R	$4,490	0.70	BBB	4.1%
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Otter Tail Corp.	*	*	$839	R	$1,703	0.90	BBB	7.5%
Pinnacle West Capital	*	*	$3,545	R	$9,757	0.70	A-	5.5%
PNM Resources	*	*	$1,449	R	$3,317	0.00	BBB+	6.6%
Portland General	*	*	$2,018	R	$4,140	0.70	BBB	4.9%
PPL Corp.	*	*	$7,353	R	$26,705	0.70	A-	2.5%
Public Serv. Enterprise			$9,078	M	$23,230	0.70	BBB+	1.8%
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Average			$6,919		$15,656	0.65	BBB+	4.8%
Subsample Average			$7,339		$16,786	0.62	BBB+	4.7%

Sources and Notes:

[1]-[2]: Denotes companies used in the CAPM and DCF subsamples.

[3]: Bloomberg as of November 30, 2017. Most recent four quarters.

[4]: See Table No. BV-ELEC-2. Key:

R - Regulated (More than 80% of assets regulated).

M - Mostly Regulated (50%-80% of assets regulated).

[5]: See Table No. BV-ELEC-3 Panels A through V.

[6]: See Supporting Schedule # 1 to Table No. BV-ELEC-10.

[7]: S&P Credit Ratings from Research Insight as of 2017 Q3.

[8]: See Table No. BV-ELEC-5.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel A: ALLETE

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$2,043	$2,043	$1,873	$1,822	$1,529	$1,288	$1,158	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	51	51	50	49	45	41	39	[b]
Price per Share - Common	15_day_Average	$78	$78	$61	$49	$46	$48	$42	[c]
Market Value of Common Equity		$3,990	$3,963	$2,997	$2,393	$2,048	$1,941	$1,616	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$3,990	$3,963	$2,997	$2,393	$2,048	$1,941	$1,616	[f]= [d]
Market to Book Value of Common Equity		1.95	1.94	1.60	1.31	1.34	1.51	1.40	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$388	$388	$362	$403	$358	$369	$278	[j]
Current Liabilities	BS_CUR_LIAB	$291	$291	$404	$318	$287	$224	$215	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$64	$64	$187	$49	$85	$38	$67	[l]
Net Working Capital		$162	$162	$144	$135	$156	$183	$131	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$0	$0	$0	$0	$3	$1	$0	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$1,445	$1,445	$1,359	$1,549	$1,289	$1,064	$948	[p]
Book Value of Long-Term Debt		$1,509	$1,509	$1,546	$1,598	$1,375	$1,102	$1,015	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$1,654	$1,654	$1,676	$1,485	$1,132	$1,144	$966	
Carrying Amount		$1,569	$1,569	$1,605	$1,374	$1,110	$1,018	$863	
Adjustment to Book Value of Long-Term Debt		$85	$85	$71	$111	$22	$126	$103	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$1,593	$1,593	$1,617	$1,709	$1,396	$1,228	$1,118	[s] = [q] + [r].
Market Value of Debt		$1,593	$1,593	$1,617	$1,709	$1,396	$1,228	$1,118	[t] = [s].
MARKET VALUE OF FIRM		$5,583	$5,556	$4,614	$4,102	$3,444	$3,169	$2,734	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		71.46%	71.32%	64.96%	58.33%	59.47%	61.26%	59.11%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		28.54%	28.68%	35.04%	41.67%	40.53%	38.74%	40.89%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel B: Alliant Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$4,154	$4,154	$3,859	$3,745	$3,436	$3,267	$3,116	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	231	231	228	227	222	222	222	[b]
Price per Share - Common	15_day_Average	$44	$42	$39	$28	$28	$25	$22	[c]
Market Value of Common Equity		$10,284	$9,787	$8,841	$6,434	$6,291	$5,494	$4,871	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$10,284	$9,787	$8,841	$6,434	$6,291	$5,494	$4,871	[f]= [d]
Market to Book Value of Common Equity		2.48	2.36	2.29	1.72	1.83	1.68	1.56	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$200	$200	$200	$200	$200	$200	$205	[h]
Market Value of Preferred Equity		$200	$200	$200	$200	$200	$200	$205	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$752	$752	$958	$1,088	$962	$880	$1,029	[j]
Current Liabilities	BS_CUR_LIAB	$1,470	$1,470	$1,370	$991	$1,742	$1,053	$946	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$105	$105	$314	$3	$493	$48	$1	[l]
Net Working Capital		($613)	($613)	($98)	$100	($287)	($124)	$84	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$485	$485	$238	$109	$354	$237	$70	[n]
Adjusted Short-Term Debt		$485	$485	$98	$0	$287	$124	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$4,255	$4,255	$3,817	$3,856	$2,800	$3,105	$2,828	[p]
Book Value of Long-Term Debt		$4,846	$4,846	$4,229	$3,859	$3,579	$3,278	$2,830	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$4,799	$4,799	$4,336	$4,418	$3,712	$3,861	$3,325	
Carrying Amount		$4,320	$4,320	$3,836	$3,790	$3,336	$3,138	$2,705	
Adjustment to Book Value of Long-Term Debt		$479	$479	$501	$629	$376	$722	$621	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$5,324	$5,324	$4,729	$4,487	$3,955	$4,000	$3,450	[s] = [q] + [r].
Market Value of Debt		$5,324	$5,324	$4,729	$4,487	$3,955	$4,000	$3,450	[t] = [s].
MARKET VALUE OF FIRM		$15,809	$15,311	$13,770	$11,121	$10,446	$9,694	$8,526	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		65.05%	63.92%	64.21%	57.85%	60.22%	56.68%	57.13%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		1.27%	1.31%	1.45%	1.80%	1.91%	2.06%	2.41%	[w] = [i] / [u].
Debt - Market Value Ratio		33.68%	34.78%	34.34%	40.35%	37.86%	41.26%	40.47%	[x] = [t] / [u].

Sources and Notes:

Bloomberg as of November 30, 2017

Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.

Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3
Market Value of the U.S. Electric Sample
Panel C: Amer. Elec. Power
($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$18,078	$18,078	$17,322	$17,699	$16,868	$15,762	$15,306	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	492	492	492	491	489	487	485	[b]
Price per Share - Common	15_day_Average	$77	$72	$65	$55	$53	$43	$44	[c]
Market Value of Common Equity		$37,653	$35,328	$32,042	$27,037	$25,812	$21,167	$21,277	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$37,653	$35,328	$32,042	$27,037	$25,812	$21,167	$21,277	[f]= [d]
Market to Book Value of Common Equity		2.08	1.95	1.85	1.53	1.53	1.34	1.39	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$4,068	$4,068	$5,949	$4,548	$4,111	$4,317	$4,648	[j]
Current Liabilities	BS_CUR_LIAB	$7,322	$7,322	$7,779	$7,058	$7,457	$5,692	$6,795	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$2,359	$2,359	$2,385	$1,826	$2,381	$1,366	$2,272	[l]
Net Working Capital		($895)	($895)	$555	($684)	($965)	($9)	$125	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$1,059	$1,059	$1,478	$782	$1,282	$1,218	$1,216	[n]
Adjusted Short-Term Debt		$895	$895	$0	$684	$965	$9	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$18,362	$18,362	$17,320	$17,600	$15,677	$16,202	$14,955	[p]
Book Value of Long-Term Debt		$21,617	$21,617	$19,705	$20,110	$19,023	$17,577	$17,227	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$22,212	$22,212	$21,201	$21,075	$19,672	$20,907	$19,259	
Carrying Amount		$20,391	$20,391	$19,573	$18,684	$18,377	$17,757	$16,516	
Adjustment to Book Value of Long-Term Debt		$1,821	$1,821	$1,629	$2,391	$1,295	$3,150	$2,743	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$23,437	$23,437	$21,333	$22,501	$20,318	$20,727	$19,970	[s] = [q] + [r].
Market Value of Debt		$23,437	$23,437	$21,333	$22,501	$20,318	$20,727	$19,970	[t] = [s].
MARKET VALUE OF FIRM		$61,090	$58,765	$53,375	$49,538	$46,130	$41,894	$41,247	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.63%	60.12%	60.03%	54.58%	55.95%	50.53%	51.58%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		38.37%	39.88%	39.97%	45.42%	44.05%	49.47%	48.42%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel D: Ameren Corp.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$7,345	$7,345	$7,193	$7,014	$6,774	$6,574	$7,874	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	243	243	243	243	243	243	243	[b]
Price per Share - Common	15_day_Average	$63	$59	$50	$40	$38	$34	$33	[c]
Market Value of Common Equity		$15,386	$14,327	$12,115	$9,802	$9,318	$8,311	$7,920	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$15,386	$14,327	$12,115	$9,802	$9,318	$8,311	$7,920	[f]= [d]
Market to Book Value of Common Equity		2.09	1.95	1.68	1.40	1.38	1.26	1.01	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$1,581	$1,581	$1,599	$1,983	$1,942	$3,273	$2,406	[j]
Current Liabilities	BS_CUR_LIAB	$2,581	$2,581	$2,291	$2,489	$2,119	$3,228	$1,546	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$777	$777	$431	$395	$119	$884	$206	[l]
Net Working Capital		($223)	($223)	($261)	($111)	($58)	$929	$1,066	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$446	$446	$608	$783	$753	$0	$5	[n]
Adjusted Short-Term Debt		$223	$223	$261	$111	$58	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$6,922	$6,922	$6,607	$5,981	$5,825	$5,274	$6,781	[p]
Book Value of Long-Term Debt		$7,922	$7,922	$7,299	$6,487	$6,002	$6,158	$6,987	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$7,772	$7,772	$7,814	$7,135	$6,584	$7,110	$7,800	
Carrying Amount		$7,276	$7,276	$7,275	$6,240	$6,038	$6,157	$6,856	
Adjustment to Book Value of Long-Term Debt		$496	$496	$539	$895	$546	$953	$944	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$8,418	$8,418	$7,838	$7,382	$6,548	$7,111	$7,931	[s] = [q] + [r].
Market Value of Debt		$8,418	$8,418	$7,838	$7,382	$6,548	$7,111	$7,931	[t] = [s].
MARKET VALUE OF FIRM		$23,804	$22,745	$19,953	$17,184	$15,866	$15,422	$15,851	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		64.64%	62.99%	60.72%	57.04%	58.73%	53.89%	49.97%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		35.36%	37.01%	39.28%	42.96%	41.27%	46.11%	50.03%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel E: CenterPoint Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$3,618	$3,618	$3,472	$4,058	$4,473	$4,261	$4,257	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	431	431	431	430	430	429	427	[b]
Price per Share - Common	15_day_Average	$29	$30	$23	$18	$24	$24	$21	[c]
Market Value of Common Equity		$12,683	$12,812	$10,097	$7,692	$10,424	$10,139	$8,997	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$12,683	$12,812	$10,097	$7,692	$10,424	$10,139	$8,997	[f]= [d]
Market to Book Value of Common Equity		3.51	3.54	2.91	1.90	2.33	2.38	2.11	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,935	$2,935	$2,529	$2,400	$2,576	$2,319	$2,752	[j]
Current Liabilities	BS_CUR_LIAB	$3,221	$3,221	$2,398	$3,191	$3,008	$2,595	$3,364	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$1,102	$1,102	$772	$938	$722	$553	$1,402	[l]
Net Working Capital		$816	$816	$903	$147	$290	$277	$790	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$48	$48	$43	$49	$80	$70	$53	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$7,531	$7,531	$7,736	$7,662	$7,797	$7,758	$8,415	[p]
Book Value of Long-Term Debt		$8,633	$8,633	$8,508	$8,600	$8,519	$8,311	$9,817	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$8,846	$8,846	$9,067	$9,427	$8,670	$10,807	$10,049	
Carrying Amount		$8,443	$8,443	$8,585	$8,652	$8,171	$9,619	$8,994	
Adjustment to Book Value of Long-Term Debt		$403	$403	$482	$775	$499	$1,188	$1,055	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$9,036	$9,036	$8,990	$9,375	$9,018	$9,499	$10,872	[s] = [q] + [r].
Market Value of Debt		$9,036	$9,036	$8,990	$9,375	$9,018	$9,499	$10,872	[t] = [s].
MARKET VALUE OF FIRM		$21,719	$21,848	$19,087	$17,067	$19,442	$19,638	$19,869	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		58.40%	58.64%	52.90%	45.07%	53.62%	51.63%	45.28%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		41.60%	41.36%	47.10%	54.93%	46.38%	48.37%	54.72%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel F: CMS Energy Corp.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$4,535	$4,535	$4,259	$3,902	$3,670	$3,396	$3,196	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	282	282	279	277	275	266	264	[b]
Price per Share - Common	15_day_Average	$50	$47	$43	$34	$30	$26	$23	[c]
Market Value of Common Equity		$13,994	$13,310	$11,917	$9,338	$8,161	$7,018	$6,141	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$13,994	$13,310	$11,917	$9,338	$8,161	$7,018	$6,141	[f]= [d]
Market to Book Value of Common Equity		3.09	2.94	2.80	2.39	2.22	2.07	1.92	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,121	$2,121	$2,198	$2,123	$2,734	$2,401	$2,360	[j]
Current Liabilities	BS_CUR_LIAB	$2,261	$2,261	$2,069	$1,788	$1,648	$1,464	$1,485	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$980	$980	$1,005	$741	$690	$532	$510	[l]
Net Working Capital		$840	$840	$1,134	$1,076	$1,776	$1,469	$1,385	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$230	$230	$75	$68	$0	$0	$0	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$9,121	$9,121	$8,832	$8,014	$8,171	$7,229	$6,866	[p]
Book Value of Long-Term Debt		$10,101	$10,101	$9,837	$8,755	$8,861	$7,761	$7,376	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$9,953	$9,953	$9,599	$9,285	$8,368	$8,347	$8,025	
Carrying Amount		$9,504	$9,504	$9,084	$8,535	$7,642	$7,229	$7,073	
Adjustment to Book Value of Long-Term Debt		$449	$449	$515	$750	$726	$1,118	$952	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$10,550	$10,550	$10,352	$9,505	$9,587	$8,879	$8,328	[s] = [q] + [r].
Market Value of Debt		$10,550	$10,550	$10,352	$9,505	$9,587	$8,879	$8,328	[t] = [s].
MARKET VALUE OF FIRM		$24,544	$23,860	$22,269	$18,843	$17,748	$15,897	$14,469	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		57.02%	55.78%	53.51%	49.56%	45.98%	44.15%	42.44%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		42.98%	44.22%	46.49%	50.44%	54.02%	55.85%	57.56%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel G: Consol. Edison

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$15,102	$15,102	$14,267	$13,040	$12,707	$12,166	$11,842	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	310	310	305	293	293	293	293	[b]
Price per Share - Common	15_day_Average	$88	$83	$76	$65	$57	$56	$60	[c]
Market Value of Common Equity		$27,135	$25,682	$23,296	$18,927	$16,614	$16,301	$17,522	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$27,135	$25,682	$23,296	$18,927	$16,614	$16,301	$17,522	[f]= [d]
Market to Book Value of Common Equity		1.80	1.70	1.63	1.45	1.31	1.34	1.48	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$3,096	$3,096	$3,154	$3,505	$3,519	$3,704	$3,240	[j]
Current Liabilities	BS_CUR_LIAB	$3,915	$3,915	$3,591	$4,429	$3,873	$4,373	$3,724	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$687	$687	$346	$761	$210	$483	$930	[l]
Net Working Capital		($132)	($132)	($91)	($163)	($144)	($186)	$446	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$356	$356	$601	$1,160	$1,425	$1,220	$340	[n]
Adjusted Short-Term Debt		$132	$132	$91	$163	$144	$186	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$14,651	$14,651	$13,747	$11,521	$10,986	$10,495	$9,841	[p]
Book Value of Long-Term Debt		$15,470	$15,470	$14,184	$12,445	$11,340	$11,164	$10,771	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$16,093	$16,093	$13,856	$13,998	$12,082	$12,935	$12,744	
Carrying Amount		$14,774	$14,774	$12,745	$12,191	$10,974	$10,768	$10,673	
Adjustment to Book Value of Long-Term Debt		$1,319	$1,319	$1,111	$1,807	$1,108	$2,167	$2,071	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$16,789	$16,789	$15,295	$14,252	$12,448	$13,331	$12,842	[s] = [q] + [r].
Market Value of Debt		$16,789	$16,789	$15,295	$14,252	$12,448	$13,331	$12,842	[t] = [s].
MARKET VALUE OF FIRM		$43,924	$42,471	$38,591	$33,179	$29,062	$29,632	$30,364	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.78%	60.47%	60.37%	57.05%	57.17%	55.01%	57.71%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		38.22%	39.53%	39.63%	42.95%	42.83%	44.99%	42.29%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel H: DTE Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$9,373	$9,373	$9,130	$8,812	$8,169	$7,876	$7,389	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	179	179	179	179	177	177	172	[b]
Price per Share - Common	15_day_Average	$114	$110	$94	$78	$76	$67	$59	[c]
Market Value of Common Equity		$20,392	$19,692	$16,898	$13,951	$13,475	$11,792	$10,192	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$20,392	$19,692	$16,898	$13,951	$13,475	$11,792	$10,192	[f]= [d]
Market to Book Value of Common Equity		2.18	2.10	1.85	1.58	1.65	1.50	1.38	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,815	$2,815	$2,595	$2,700	$2,755	$2,549	$2,730	[j]
Current Liabilities	BS_CUR_LIAB	$2,598	$2,598	$1,969	$2,273	$2,805	$3,008	$2,309	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$109	$109	$15	$468	$274	$896	$633	[l]
Net Working Capital		$326	$326	$641	$895	$224	$437	$1,054	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$659	$659	$410	$185	$653	$271	$98	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$11,795	$11,795	$9,478	$8,856	$7,909	$6,846	$7,120	[p]
Book Value of Long-Term Debt		$11,904	$11,904	$9,493	$9,324	$8,183	$7,742	$7,753	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$11,905	$11,905	$9,835	$9,503	$8,475	$8,893	$8,757	
Carrying Amount		$11,270	$11,270	$9,210	$8,606	$8,094	$7,813	$7,682	
Adjustment to Book Value of Long-Term Debt		$635	$635	$625	$897	$381	$1,080	$1,075	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$12,539	$12,539	$10,118	$10,221	$8,564	$8,822	$8,828	[s] = [q] + [r].
Market Value of Debt		$12,539	$12,539	$10,118	$10,221	$8,564	$8,822	$8,828	[t] = [s].
MARKET VALUE OF FIRM		$32,931	$32,231	$27,016	$24,172	$22,039	$20,614	$19,020	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.92%	61.10%	62.55%	57.71%	61.14%	57.20%	53.59%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		38.08%	38.90%	37.45%	42.29%	38.86%	42.80%	46.41%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel I: Duke Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$41,631	$41,631	$40,489	$39,832	$41,412	$41,165	$40,905	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	700	700	689	688	707	706	704	[b]
Price per Share - Common	15_day_Average	$89	$86	$81	$70	$74	$67	$64	[c]
Market Value of Common Equity		$62,474	$60,010	$55,487	$47,883	$52,276	$47,133	$45,201	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$62,474	$60,010	$55,487	$47,883	$52,276	$47,133	$45,201	[f]= [d]
Market to Book Value of Common Equity		1.50	1.44	1.37	1.20	1.26	1.14	1.11	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$93	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$93	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$7,706	$7,706	$13,534	$10,195	$11,575	$10,418	$10,106	[j]
Current Liabilities	BS_CUR_LIAB	$10,820	$10,820	$12,076	$10,516	$8,251	$9,239	$8,556	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$2,485	$2,485	$3,201	$2,536	$1,156	$2,307	$2,488	[l]
Net Working Capital		($629)	($629)	$4,659	$2,215	$4,480	$3,486	$4,038	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$1,899	$1,899	$3,011	$2,419	$1,787	$1,278	$875	[n]
Adjusted Short-Term Debt		$629	$629	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$48,929	$48,929	$43,964	$37,667	$38,702	$37,402	$36,109	[p]
Book Value of Long-Term Debt		$52,043	$52,043	$47,165	$40,203	$39,858	$39,709	$38,597	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$49,161	$49,161	$41,767	$44,566	$42,592	$44,001	$23,053	
Carrying Amount		$47,895	$47,895	$38,868	$40,020	$40,256	$39,461	$20,573	
Adjustment to Book Value of Long-Term Debt		$1,266	$1,266	$2,899	$4,546	$2,336	$4,540	$2,480	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$53,309	$53,309	$50,064	$44,749	$42,194	$44,249	$41,077	[s] = [q] + [r].
Market Value of Debt		$53,309	$53,309	$50,064	$44,749	$42,194	$44,249	$41,077	[t] = [s].
MARKET VALUE OF FIRM		$115,783	$113,319	$105,551	$92,632	$94,470	$91,382	$86,371	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		53.96%	52.96%	52.57%	51.69%	55.34%	51.58%	52.33%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	0.11%	[w] = [i] / [u].
Debt - Market Value Ratio		46.04%	47.04%	47.43%	48.31%	44.66%	48.42%	47.56%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel J: Edison Int'l

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$12,416	$12,416	$11,814	$11,600	$10,736	$9,689	$10,023	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	326	326	326	326	326	326	326	[b]
Price per Share - Common	15_day_Average	$81	$80	$74	$61	$57	$46	$45	[c]
Market Value of Common Equity		$26,382	$25,912	$23,951	$19,740	$18,584	$14,938	$14,719	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$26,382	$25,912	$23,951	$19,740	$18,584	$14,938	$14,719	[f]= [d]
Market to Book Value of Common Equity		2.12	2.09	2.03	1.70	1.73	1.54	1.47	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$2,194	$2,194	$2,191	$2,020	$2,022	$1,753	$1,759	[h]
Market Value of Preferred Equity		$2,194	$2,194	$2,191	$2,020	$2,022	$1,753	$1,759	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,758	$2,758	$2,605	$3,792	$4,498	$3,603	$4,494	[j]
Current Liabilities	BS_CUR_LIAB	$5,409	$5,409	$5,342	$5,239	$5,849	$5,389	$4,274	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$583	$583	$881	$295	$704	$401	$565	[l]
Net Working Capital		($2,068)	($2,068)	($1,856)	($1,152)	($647)	($1,385)	$785	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$908	$908	$757	$1,154	$1,349	$1,528	$429	[n]
Adjusted Short-Term Debt		$908	$908	$757	$1,152	$647	$1,385	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$11,638	$11,638	$10,407	$10,957	$10,133	$9,232	$13,708	[p]
Book Value of Long-Term Debt		$13,129	$13,129	$12,045	$12,404	$11,484	$11,018	$14,273	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$12,368	$12,368	$12,252	$12,319	$11,084	$10,944	$10,548	
Carrying Amount		$11,156	$11,156	$11,178	$10,738	$10,426	$9,231	$8,834	
Adjustment to Book Value of Long-Term Debt		$1,212	$1,212	$1,074	$1,581	$658	$1,713	$1,714	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$14,341	$14,341	$13,119	$13,985	$12,142	$12,731	$15,987	[s] = [q] + [r].
Market Value of Debt		$14,341	$14,341	$13,119	$13,985	$12,142	$12,731	$15,987	[t] = [s].
MARKET VALUE OF FIRM		$42,917	$42,447	$39,261	$35,745	$32,748	$29,422	$32,465	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.47%	61.05%	61.00%	55.22%	56.75%	50.77%	45.34%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		5.11%	5.17%	5.58%	5.65%	6.17%	5.96%	5.42%	[w] = [i] / [u].
Debt - Market Value Ratio		33.42%	33.79%	33.41%	39.12%	37.08%	43.27%	49.24%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel K: El Paso Electric

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$1,136	$1,136	$1,075	$1,021	$1,016	$894	$830	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	40	40	40	40	40	40	40	[b]
Price per Share - Common	15_day_Average	$60	$55	$47	$36	$37	$33	$34	[c]
Market Value of Common Equity		$2,413	$2,230	$1,886	$1,432	$1,481	$1,328	$1,356	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$2,413	$2,230	$1,886	$1,432	$1,481	$1,328	$1,356	[f]= [d]
Market to Book Value of Common Equity		2.12	1.96	1.75	1.40	1.46	1.49	1.63	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$199	$199	$192	$202	$207	$237	$176	[j]
Current Liabilities	BS_CUR_LIAB	$316	$316	$294	$251	$242	$141	$174	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$83	$83	$83	$0	$15	$0	$33	[l]
Net Working Capital		($34)	($34)	($19)	($48)	($19)	$96	$35	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$168	$168	$55	$119	$90	$15	$62	[n]
Adjusted Short-Term Debt		$34	$34	$19	$48	$19	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$1,196	$1,196	$1,195	$1,134	$985	$1,000	$850	[p]
Book Value of Long-Term Debt		$1,313	$1,313	$1,297	$1,182	$1,019	$1,000	$883	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$1,500	$1,500	$1,285	$1,314	$1,059	$1,182	$1,057	
Carrying Amount		$1,360	$1,360	$1,264	$1,164	$1,014	$1,022	$883	
Adjustment to Book Value of Long-Term Debt		$139	$139	$20	$150	$45	$160	$174	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$1,452	$1,452	$1,318	$1,332	$1,064	$1,160	$1,057	[s] = [q] + [r].
Market Value of Debt		$1,452	$1,452	$1,318	$1,332	$1,064	$1,160	$1,057	[t] = [s].
MARKET VALUE OF FIRM		$3,865	$3,682	$3,204	$2,764	$2,544	$2,487	$2,414	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		62.43%	60.56%	58.88%	51.80%	58.19%	53.38%	56.19%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		37.57%	39.44%	41.12%	48.20%	41.81%	46.62%	43.81%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel L: Entergy Corp.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$8,690	$8,690	$10,069	$9,157	$10,149	$9,408	$9,191	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	180	180	179	178	180	178	178	[b]
Price per Share - Common	15_day_Average	$86	$78	$79	$64	$76	$64	$69	[c]
Market Value of Common Equity		$15,467	$13,998	$14,147	$11,376	$13,736	$11,359	$12,194	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$15,467	$13,998	$14,147	$11,376	$13,736	$11,359	$12,194	[f]= [d]
Market to Book Value of Common Equity		1.78	1.61	1.40	1.24	1.35	1.21	1.33	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$203	$203	$233	$211	$305	$281	$281	[h]
Market Value of Preferred Equity		$203	$203	$233	$211	$305	$281	$281	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$3,471	$3,471	$4,340	$4,117	$4,265	$3,490	$3,808	[j]
Current Liabilities	BS_CUR_LIAB	$4,461	$4,461	$3,452	$3,454	$4,454	$3,439	$3,924	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$871	$871	$753	$281	$1,117	$209	$792	[l]
Net Working Capital		($118)	($118)	$1,641	$945	$927	$260	$675	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$1,353	$1,353	$433	$782	$891	$1,106	$356	[n]
Adjusted Short-Term Debt		$118	$118	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$14,000	$14,000	$13,887	$13,080	$11,665	$12,308	$11,784	[p]
Book Value of Long-Term Debt		$14,990	$14,990	$14,640	$13,362	$12,782	$12,517	$12,575	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$14,816	$14,816	$13,579	$13,607	$12,440	$12,849	$12,176	
Carrying Amount		$14,833	$14,833	$13,326	$13,399	$12,596	$12,639	$12,236	
Adjustment to Book Value of Long-Term Debt		($17)	($17)	$253	$208	($156)	$210	($60)	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$14,973	$14,973	$14,892	$13,569	$12,625	$12,728	$12,515	[s] = [q] + [r].
Market Value of Debt		$14,973	$14,973	$14,892	$13,569	$12,625	$12,728	$12,515	[t] = [s].
MARKET VALUE OF FIRM		$30,644	$29,174	$29,272	$25,156	$26,665	$24,367	$24,989	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		50.48%	47.98%	48.33%	45.22%	51.51%	46.62%	48.80%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		0.66%	0.70%	0.80%	0.84%	1.14%	1.15%	1.12%	[w] = [i] / [u].
Debt - Market Value Ratio		48.86%	51.32%	50.88%	53.94%	47.35%	52.23%	50.08%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel M: IDACORP Inc.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$2,248	$2,248	$2,149	$2,050	$1,949	$1,860	$1,770	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	50	50	50	50	50	50	50	[b]
Price per Share - Common	15_day_Average	$97	$89	$79	$61	$55	$48	$43	[c]
Market Value of Common Equity		$4,888	$4,490	$3,961	$3,087	$2,753	$2,403	$2,151	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$4,888	$4,490	$3,961	$3,087	$2,753	$2,403	$2,151	[f]= [d]
Market to Book Value of Common Equity		2.17	2.00	1.84	1.51	1.41	1.29	1.21	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$458	$458	$460	$494	$475	$567	$366	[j]
Current Liabilities	BS_CUR_LIAB	$226	$226	$205	$205	$240	$335	$268	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$0	$0	$1	$1	$1	$71	$1	[l]
Net Working Capital		$232	$232	$256	$290	$237	$303	$99	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$2	$2	$5	$4	$32	$53	$51	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$1,746	$1,746	$1,746	$1,742	$1,614	$1,615	$1,537	[p]
Book Value of Long-Term Debt		$1,746	$1,746	$1,747	$1,743	$1,615	$1,686	$1,538	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$1,859	$1,859	$1,813	$1,788	$1,600	$1,819	$1,738	
Carrying Amount		$1,746	$1,746	$1,726	$1,616	$1,616	$1,538	$1,492	
Adjustment to Book Value of Long-Term Debt		$113	$113	$87	$173	($16)	$282	$246	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$1,859	$1,859	$1,833	$1,916	$1,599	$1,968	$1,784	[s] = [q] + [r].
Market Value of Debt		$1,859	$1,859	$1,833	$1,916	$1,599	$1,968	$1,784	[t] = [s].
MARKET VALUE OF FIRM		$6,747	$6,348	$5,795	$5,003	$4,353	$4,370	$3,934	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		72.45%	70.72%	68.36%	61.71%	63.26%	54.97%	54.66%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		27.55%	29.28%	31.64%	38.29%	36.74%	45.03%	45.34%	[x] = [t] / [u].

Sources and Notes:

Bloomberg as of November 30, 2017

Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.

Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel N: MGE Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$753	$753	$720	$689	$654	$613	$578	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	35	35	35	35	35	35	35	[b]
Price per Share - Common	15_day_Average	$65	$65	$57	$40	$39	$36	$35	[c]
Market Value of Common Equity		$2,264	$2,265	$1,975	$1,396	$1,340	$1,244	$1,223	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$2,264	$2,265	$1,975	$1,396	$1,340	$1,244	$1,223	[f]= [d]
Market to Book Value of Common Equity		3.01	3.01	2.74	2.03	2.05	2.03	2.11	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$255	$255	$249	$242	$225	$214	$220	[j]
Current Liabilities	BS_CUR_LIAB	$85	$85	$86	$74	$82	$79	$60	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$4	$4	$4	$4	$4	$4	$3	[l]
Net Working Capital		$175	$175	$167	$172	$147	$139	$162	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$7	$7	$0	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$389	$389	$384	$392	$396	$400	$359	[p]
Book Value of Long-Term Debt		$394	$394	$388	$396	$400	$405	$362	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$430	$430	$436	$457	$432	$427	$433	
Carrying Amount		$391	$391	$396	$400	$404	$362	$364	
Adjustment to Book Value of Long-Term Debt		$39	$39	$40	$58	$28	$66	$68	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$433	$433	$428	$454	$429	$470	$430	[s] = [q] + [r].
Market Value of Debt		$433	$433	$428	$454	$429	$470	$430	[t] = [s].
MARKET VALUE OF FIRM		$2,696	$2,698	$2,404	$1,850	$1,769	$1,714	$1,653	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		83.95%	83.96%	82.18%	75.46%	75.77%	72.56%	73.97%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		16.05%	16.04%	17.82%	24.54%	24.23%	27.44%	26.03%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel O: OGE Energy

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$3,617	$3,617	$3,445	$3,353	$3,243	$2,995	$2,769	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	200	200	200	200	199	198	197	[b]
Price per Share - Common	15_day_Average	$35	$36	$32	$27	$36	$36	$28	[c]
Market Value of Common Equity		$7,041	$7,219	$6,386	$5,399	$7,266	$7,104	$5,440	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$7,041	$7,219	$6,386	$5,399	$7,266	$7,104	$5,440	[f]= [d]
Market to Book Value of Common Equity		1.95	2.00	1.85	1.61	2.24	2.37	1.96	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$600	$600	$547	$753	$740	$758	$857	[j]
Current Liabilities	BS_CUR_LIAB	$954	$954	$795	$587	$869	$942	$1,196	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$350	$350	$125	$110	$0	$0	$0	[l]
Net Working Capital		($4)	($4)	($123)	$276	($129)	($184)	($339)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$147	$147	$213	$0	$411	$447	$456	[n]
Adjusted Short-Term Debt		$4	$4	$123	$0	$129	$184	$339	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$2,750	$2,750	$2,505	$2,646	$2,510	$2,400	$2,848	[p]
Book Value of Long-Term Debt		$3,103	$3,103	$2,753	$2,756	$2,639	$2,584	$3,188	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$2,904	$2,904	$2,999	$2,550	$2,653	$3,397	$3,276	
Carrying Amount		$2,631	$2,631	$2,739	$2,755	$2,400	$2,849	$2,737	
Adjustment to Book Value of Long-Term Debt		$273	$273	$260	($206)	$253	$548	$539	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$3,377	$3,377	$3,014	$2,550	$2,891	$3,132	$3,726	[s] = [q] + [r].
Market Value of Debt		$3,377	$3,377	$3,014	$2,550	$2,891	$3,132	$3,726	[t] = [s].
MARKET VALUE OF FIRM		$10,417	$10,596	$9,400	$7,949	$10,157	$10,236	$9,166	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		67.59%	68.13%	67.94%	67.92%	71.54%	69.41%	59.35%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		32.41%	31.87%	32.06%	32.08%	28.46%	30.59%	40.65%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel P: Otter Tail Corp.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$693	$693	$657	$598	$563	$530	$531	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	40	40	39	38	37	36	36	[b]
Price per Share - Common	15_day_Average	$47	$43	$35	$26	$27	$28	$24	[c]
Market Value of Common Equity		$1,843	$1,703	$1,380	$972	$1,007	$1,006	$859	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$1,843	$1,703	$1,380	$972	$1,007	$1,006	$859	[f]= [d]
Market to Book Value of Common Equity		2.66	2.46	2.10	1.63	1.79	1.90	1.62	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$16	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$16	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$228	$228	$204	$274	$298	$310	$299	[j]
Current Liabilities	BS_CUR_LIAB	$246	$246	$246	$237	$200	$220	$176	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$0	$0	$85	$0	$0	$0	$0	[l]
Net Working Capital		($18)	($18)	$43	$37	$98	$91	$123	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$104	$104	$37	$87	$39	$40	$12	[n]
Adjusted Short-Term Debt		$18	$18	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$490	$490	$461	$498	$499	$437	$422	[p]
Book Value of Long-Term Debt		$508	$508	$546	$499	$499	$437	$422	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$584	$584	$561	$601	$428	$491	$525	
Carrying Amount		$539	$539	$496	$499	$390	$422	$472	
Adjustment to Book Value of Long-Term Debt		$45	$45	$65	$102	$38	$69	$53	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$554	$554	$611	$601	$537	$507	$475	[s] = [q] + [r].
Market Value of Debt		$554	$554	$611	$601	$537	$507	$475	[t] = [s].
MARKET VALUE OF FIRM		$2,397	$2,257	$1,991	$1,573	$1,544	$1,513	$1,350	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		76.90%	75.47%	69.31%	61.81%	65.24%	66.49%	63.66%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	1.15%	[w] = [i] / [u].
Debt - Market Value Ratio		23.10%	24.53%	30.69%	38.19%	34.76%	33.51%	35.19%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel Q: Pinnacle West Capital

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$5,142	$5,142	$4,853	$4,654	$4,492	$4,276	$4,056	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	112	112	111	111	110	110	110	[b]
Price per Share - Common	15_day_Average	$90	$87	$77	$62	$56	$55	$53	[c]
Market Value of Common Equity		$10,064	$9,757	$8,563	$6,850	$6,196	$6,003	$5,792	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$10,064	$9,757	$8,563	$6,850	$6,196	$6,003	$5,792	[f]= [d]
Market to Book Value of Common Equity		1.96	1.90	1.76	1.47	1.38	1.40	1.43	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$1,174	$1,174	$977	$1,062	$1,041	$1,350	$1,099	[j]
Current Liabilities	BS_CUR_LIAB	$1,303	$1,303	$1,110	$1,523	$1,449	$1,447	$949	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$207	$207	$17	$411	$369	$566	$90	[l]
Net Working Capital		$78	$78	($115)	($50)	($39)	$470	$240	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$131	$131	$117	$57	$19	$0	$0	[n]
Adjusted Short-Term Debt		$0	$0	$115	$50	$19	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$4,491	$4,491	$4,145	$3,257	$3,038	$2,820	$3,339	[p]
Book Value of Long-Term Debt		$4,698	$4,698	$4,278	$3,719	$3,426	$3,387	$3,429	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$4,426	$4,426	$4,106	$3,839	$3,579	$3,875	$3,926	
Carrying Amount		$4,147	$4,147	$3,820	$3,415	$3,337	$3,322	$3,496	
Adjustment to Book Value of Long-Term Debt		$279	$279	$286	$424	$242	$553	$430	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$4,977	$4,977	$4,564	$4,143	$3,668	$3,940	$3,859	[s] = [q] + [r].
Market Value of Debt		$4,977	$4,977	$4,564	$4,143	$3,668	$3,940	$3,859	[t] = [s].
MARKET VALUE OF FIRM		$15,041	$14,734	$13,127	$10,993	$9,864	$9,943	$9,651	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		66.91%	66.22%	65.23%	62.31%	62.81%	60.38%	60.01%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		33.09%	33.78%	34.77%	37.69%	37.19%	39.62%	39.99%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel R: PNM Resources

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$1,766	$1,766	$1,688	$1,763	$1,723	$1,665	$1,632	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	80	80	80	80	80	80	80	[b]
Price per Share - Common	15_day_Average	$45	$42	$33	$26	$26	$22	$21	[c]
Market Value of Common Equity		$3,555	$3,317	$2,640	$2,094	$2,053	$1,766	$1,655	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$3,555	$3,317	$2,640	$2,094	$2,053	$1,766	$1,655	[f]= [d]
Market to Book Value of Common Equity		2.01	1.88	1.56	1.19	1.19	1.06	1.01	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$12	$12	$12	$12	$12	$12	$12	[h]
Market Value of Preferred Equity		$12	$12	$12	$12	$12	$12	$12	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$375	$375	$399	$408	$466	$401	$472	[j]
Current Liabilities	BS_CUR_LIAB	$711	$711	$702	$519	$700	$416	$393	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$165	$165	$101	$125	$333	$53	$2	[l]
Net Working Capital		($171)	($171)	($202)	$14	$99	$37	$82	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$267	$267	$356	$103	$100	$112	$113	[n]
Adjusted Short-Term Debt		$171	$171	$202	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$2,282	$2,282	$2,207	$1,980	$1,542	$1,696	$1,672	[p]
Book Value of Long-Term Debt		$2,619	$2,619	$2,510	$2,105	$1,875	$1,749	$1,675	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$1,730	$1,730	$1,703	$1,624	$1,383	$1,385	$1,295	
Carrying Amount		$1,631	$1,631	$1,581	$1,483	$1,291	$1,216	$1,216	
Adjustment to Book Value of Long-Term Debt		$99	$99	$123	$142	$92	$170	$79	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$2,718	$2,718	$2,632	$2,247	$1,967	$1,919	$1,754	[s] = [q] + [r].
Market Value of Debt		$2,718	$2,718	$2,632	$2,247	$1,967	$1,919	$1,754	[t] = [s].
MARKET VALUE OF FIRM		$6,284	$6,046	$5,284	$4,353	$4,032	$3,697	$3,420	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		56.57%	54.86%	49.97%	48.11%	50.91%	47.78%	48.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		0.18%	0.19%	0.22%	0.26%	0.29%	0.31%	0.34%	[w] = [i] / [u].
Debt - Market Value Ratio		43.25%	44.95%	49.82%	51.62%	48.80%	51.90%	51.28%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel S: Portland General

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$2,402	$2,402	$2,310	$2,232	$1,889	$1,792	$1,717	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	89	89	89	89	78	78	76	[b]
Price per Share - Common	15_day_Average	$49	$46	$43	$36	$33	$28	$27	[c]
Market Value of Common Equity		$4,365	$4,140	$3,833	$3,155	$2,567	$2,212	$2,059	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$4,365	$4,140	$3,833	$3,155	$2,567	$2,212	$2,059	[f]= [d]
Market to Book Value of Common Equity		1.82	1.72	1.66	1.41	1.36	1.23	1.20	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$466	$466	$476	$605	$542	$565	$784	[j]
Current Liabilities	BS_CUR_LIAB	$491	$491	$448	$465	$482	$380	$648	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$100	$100	$0	$0	$70	$50	$200	[l]
Net Working Capital		$75	$75	$28	$140	$130	$235	$336	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$0	$0	$0	$0	$0	$0	$0	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$2,277	$2,277	$2,325	$2,204	$2,251	$1,761	$1,536	[p]
Book Value of Long-Term Debt		$2,377	$2,377	$2,325	$2,204	$2,321	$1,811	$1,736	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$2,693	$2,693	$2,455	$2,901	$2,074	$1,949	$2,091	
Carrying Amount		$2,350	$2,350	$2,193	$2,501	$1,916	$1,636	$1,735	
Adjustment to Book Value of Long-Term Debt		$343	$343	$262	$400	$158	$313	$356	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$2,720	$2,720	$2,587	$2,604	$2,479	$2,124	$2,092	[s] = [q] + [r].
Market Value of Debt		$2,720	$2,720	$2,587	$2,604	$2,479	$2,124	$2,092	[t] = [s].
MARKET VALUE OF FIRM		$7,085	$6,860	$6,420	$5,759	$5,046	$4,336	$4,151	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.61%	60.35%	59.71%	54.79%	50.87%	51.02%	49.60%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		38.39%	39.65%	40.29%	45.21%	49.13%	48.98%	50.40%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel T: PPL Corp.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$10,692	$10,692	$9,975	$10,222	$13,974	$12,344	$11,214	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	688	688	679	672	665	630	581	[b]
Price per Share - Common	15_day_Average	$36	$39	$35	$31	$31	$28	$27	[c]
Market Value of Common Equity		$25,070	$26,705	$23,739	$20,835	$20,387	$17,754	$15,591	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$25,070	$26,705	$23,739	$20,835	$20,387	$17,754	$15,591	[f]= [d]
Market to Book Value of Common Equity		2.34	2.50	2.38	2.04	1.46	1.44	1.39	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,331	$2,331	$2,099	$2,990	$5,760	$4,971	$5,227	[j]
Current Liabilities	BS_CUR_LIAB	$4,149	$4,149	$3,412	$4,468	$5,412	$4,948	$4,887	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$448	$448	$443	$1,460	$235	$751	$313	[l]
Net Working Capital		($1,370)	($1,370)	($870)	($18)	$583	$774	$653	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$1,211	$1,211	$636	$557	$1,099	$499	$526	[n]
Adjusted Short-Term Debt		$1,211	$1,211	$636	$18	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$19,110	$19,110	$18,069	$17,745	$20,522	$19,092	$18,711	[p]
Book Value of Long-Term Debt		$20,769	$20,769	$19,148	$19,223	$20,757	$19,843	$19,024	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$21,355	$21,355	$21,218	$32,170	$35,517	$35,217	$32,271	
Carrying Amount		$18,326	$18,326	$19,048	$28,602	$33,756	$31,744	$29,762	
Adjustment to Book Value of Long-Term Debt		$3,029	$3,029	$2,170	$3,568	$1,761	$3,473	$2,509	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$23,798	$23,798	$21,318	$22,791	$22,518	$23,316	$21,533	[s] = [q] + [r].
Market Value of Debt		$23,798	$23,798	$21,318	$22,791	$22,518	$23,316	$21,533	[t] = [s].
MARKET VALUE OF FIRM		$48,868	$50,503	$45,057	$43,626	$42,905	$41,070	$37,124	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		51.30%	52.88%	52.69%	47.76%	47.52%	43.23%	42.00%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		48.70%	47.12%	47.31%	52.24%	52.48%	56.77%	58.00%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
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Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel U: Public Serv. Enterprise

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$13,124	$13,124	$13,476	$12,933	$12,083	$11,338	$10,806	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	505	505	505	505	506	506	506	[b]
Price per Share - Common	15_day_Average	$52	$46	$43	$40	$38	$33	$32	[c]
Market Value of Common Equity		$26,016	$23,230	$21,487	$20,317	$18,979	$16,702	$16,052	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$26,016	$23,230	$21,487	$20,317	$18,979	$16,702	$16,052	[f]= [d]
Market to Book Value of Common Equity		1.98	1.77	1.59	1.57	1.57	1.47	1.49	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$3,081	$3,081	$3,209	$3,204	$3,846	$3,741	$3,978	[j]
Current Liabilities	BS_CUR_LIAB	$3,831	$3,831	$2,804	$3,604	$3,136	$3,235	$3,039	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$1,250	$1,250	$0	$1,106	$574	$1,010	$975	[l]
Net Working Capital		$500	$500	$405	$706	$1,284	$1,516	$1,914	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$202	$202	$255	$20	$0	$0	$16	[n]
Adjusted Short-Term Debt		$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$11,274	$11,274	$10,697	$8,132	$8,389	$7,476	$7,334	[p]
Book Value of Long-Term Debt		$12,524	$12,524	$10,697	$9,238	$8,963	$8,486	$8,309	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$12,003	$12,003	$10,256	$10,149	$9,061	$9,324	$9,283	
Carrying Amount		$11,395	$11,395	$9,568	$9,144	$8,643	$7,939	$8,094	
Adjustment to Book Value of Long-Term Debt		$608	$608	$688	$1,005	$418	$1,385	$1,189	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$13,132	$13,132	$11,385	$10,243	$9,381	$9,871	$9,498	[s] = [q] + [r].
Market Value of Debt		$13,132	$13,132	$11,385	$10,243	$9,381	$9,871	$9,498	[t] = [s].
MARKET VALUE OF FIRM		$39,148	$36,362	$32,872	$30,560	$28,360	$26,573	$25,550	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		66.46%	63.89%	65.37%	66.48%	66.92%	62.85%	62.83%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		33.54%	36.11%	34.63%	33.52%	33.08%	37.15%	37.17%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-3

Market Value of the U.S. Electric Sample

Panel V: Xcel Energy Inc.

($MM)

		DCF Capital Structure	3rd Quarter, 2017	3rd Quarter, 2016	3rd Quarter, 2015	3rd Quarter, 2014	3rd Quarter, 2013	3rd Quarter, 2012	Notes
MARKET VALUE OF COMMON EQUITY		DCF Capital Structure	09/30/17	09/30/16	09/30/15	09/30/14	09/30/13	09/30/12	
Book Value, Common Shareholder's Equity	TOT_COMMON_EQY	$11,123	$11,123	$10,988	$10,545	$10,155	$9,547	$8,850	[a]
Shares Outstanding (in millions) - Common	BS_SH_OUT	508	508	508	507	505	498	488	[b]
Price per Share - Common	15_day_Average	$51	$48	$42	$34	$31	$28	$28	[c]
Market Value of Common Equity		$25,861	$24,546	$21,223	$17,219	$15,664	$13,799	$13,528	[d] = [b] x [c].
Market Value of GP Equity		n/a	n/a	n/a	n/a	n/a	n/a	n/a	[e]
Total Market Value of Equity		$25,861	$24,546	$21,223	$17,219	$15,664	$13,799	$13,528	[f]= [d]
Market to Book Value of Common Equity		2.32	2.21	1.93	1.63	1.54	1.45	1.53	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY									
Book Value of Preferred Equity	BS_PFD_EQY	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity		$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT									
Current Assets	BS_CUR_ASSET_REPORT	$2,899	$2,899	$3,076	$3,344	$3,197	$3,121	$3,371	[j]
Current Liabilities	BS_CUR_LIAB	$3,340	$3,340	$3,454	$3,085	$3,471	$2,839	$3,161	[k]
Current Portion of Long-Term Debt	BS_ST_PORTION_OF_LT_DEBT	$305	$305	$710	$457	$258	$281	$859	[l]
Net Working Capital		($136)	($136)	$332	$717	($17)	$562	$1,070	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	BS_ST_DEBT	$514	$514	$366	$64	$697	$302	$304	[n]
Adjusted Short-Term Debt		$136	$136	$0	$0	$17	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	BS_LT_BORROW	$14,573	$14,573	$13,403	$12,691	$11,502	$10,914	$10,106	[p]
Book Value of Long-Term Debt		$15,014	$15,014	$14,112	$13,148	$11,776	$11,195	$10,965	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt		$15,513	$15,513	$14,095	$13,360	$11,879	$12,208	$11,735	
Carrying Amount		$14,450	$14,450	$13,056	$11,757	$11,192	$10,402	$9,908	
Adjustment to Book Value of Long-Term Debt		$1,063	$1,063	$1,039	$1,603	$687	$1,806	$1,826	[r] = See Sources and Notes.
Market Value of Long-Term Debt		$16,077	$16,077	$15,151	$14,751	$12,463	$13,001	$12,792	[s] = [q] + [r].
Market Value of Debt		$16,077	$16,077	$15,151	$14,751	$12,463	$13,001	$12,792	[t] = [s].
MARKET VALUE OF FIRM		$41,939	$40,624	$36,374	$31,970	$28,128	$26,800	$26,319	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS									
Common Equity - Market Value Ratio		61.66%	60.42%	58.35%	53.86%	55.69%	51.49%	51.40%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio		-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio		38.34%	39.58%	41.65%	46.14%	44.31%	48.51%	48.60%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of November 30, 2017
Capital structure from 3rd Quarter, 2017 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 3rd Quarter, 2017 balance sheet information and a 15-trading day average closing price ending on 11/30/2017.
Prices are reported in Supporting Schedule #1 to Table No. BV-ELEC-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [n] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2016 10-K.

Table No. BV-ELEC-4

Capital Structure Summary

Company	DCF Analysis	CAPM Analysis	DCF Capital Structure: Common Equity - Value Ratio [1]	DCF Capital Structure: Preferred Equity - Value Ratio [2]	DCF Capital Structure: Debt - Value Ratio [3]	5-Year Average Capital Structure: Common Equity - Value Ratio [4]	5-Year Average Capital Structure: Preferred Equity - Value Ratio [5]	5-Year Average Capital Structure: Debt - Value Ratio [6]
ALLETE			71.5%	0.0%	28.5%	61.8%	0.0%	38.2%
Alliant Energy	*	*	65.1%	1.3%	33.7%	59.9%	1.8%	38.3%
Amer. Elec. Power	*	*	61.6%	0.0%	38.4%	55.4%	0.0%	44.6%
Ameren Corp.	*	*	64.6%	0.0%	35.4%	57.4%	0.0%	42.6%
CenterPoint Energy			58.4%	0.0%	41.6%	51.0%	0.0%	49.0%
CMS Energy Corp.	*	*	57.0%	0.0%	43.0%	48.5%	0.0%	51.5%
Consol. Edison	*	*	61.8%	0.0%	38.2%	57.7%	0.0%	42.3%
DTE Energy	*	*	61.9%	0.0%	38.1%	59.2%	0.0%	40.8%
Duke Energy	*	*	54.0%	0.0%	46.0%	52.8%	0.0%	47.2%
Edison Int'l	*	*	61.5%	5.1%	33.4%	55.4%	5.7%	38.9%
El Paso Electric	*	*	62.4%	0.0%	37.6%	56.1%	0.0%	43.9%
Entergy Corp.	*	*	50.5%	0.7%	48.9%	48.0%	1.0%	51.0%
IDACORP Inc.	*	*	72.4%	0.0%	27.6%	62.2%	0.0%	37.8%
MGE Energy			84.0%	0.0%	16.0%	77.0%	0.0%	23.0%
OGE Energy	*	*	67.6%	0.0%	32.4%	68.1%	0.0%	31.9%
Otter Tail Corp.	*	*	76.9%	0.0%	23.1%	66.5%	0.1%	33.4%
Pinnacle West Capital	*	*	66.9%	0.0%	33.1%	62.8%	0.0%	37.2%
PNM Resources	*	*	56.6%	0.2%	43.2%	49.7%	0.3%	50.1%
Portland General	*	*	61.6%	0.0%	38.4%	54.3%	0.0%	45.7%
PPL Corp.	*	*	51.3%	0.0%	48.7%	47.7%	0.0%	52.3%
Public Serv. Enterprise			66.5%	0.0%	33.5%	65.0%	0.0%	35.0%
Xcel Energy Inc.	*	*	61.7%	0.0%	38.3%	55.1%	0.0%	44.9%
Average			63.4%	0.3%	36.2%	57.8%	0.4%	41.8%
Regulated Subsample Average			62.0%	0.4%	37.6%	56.5%	0.5%	43.0%

Sources and Notes:
[1], [4]: Supporting Schedule #1 to Table No. BV-ELEC-4.
[2], [5]: Supporting Schedule #2 to Table No. BV-ELEC-4.
[3], [6]: Supporting Schedule #3 to Table No. BV-ELEC-4.
Values in this table may not add up exactly to 100% because of rounding.

Table No. BV-ELEC-5

Estimated Growth Rates

Company	ThomsonOne IBES Estimate		Value Line			
	Long-Term Growth Rate	Number of Estimates	EPS Year 2017 Estimate	EPS Year 2020-2022 Estimate	Annualized Growth Rate	Combined Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	n/a	n/a	$3.30	$4.00	4.9%	4.9%
Alliant Energy	7.1%	2	$2.00	$2.50	5.7%	6.6%
Amer. Elec. Power	2.8%	3	$3.60	$4.75	7.2%	3.9%
Ameren Corp.	7.0%	1	$2.75	$3.50	6.2%	6.6%
CenterPoint Energy	7.4%	4	$1.35	$1.65	5.1%	6.9%
CMS Energy Corp.	7.4%	4	$2.15	$2.75	6.3%	7.2%
Consol. Edison	3.2%	3	$4.05	$4.50	2.7%	3.1%
DTE Energy	4.9%	3	$5.75	$6.75	4.1%	4.7%
Duke Energy	3.2%	3	$4.60	$5.25	3.4%	3.3%
Edison Int'l	5.8%	2	$4.25	$5.25	5.4%	5.7%
El Paso Electric	5.3%	1	$2.45	$3.00	5.2%	5.2%
Entergy Corp.	-5.4%	2	$4.80	$5.00	1.0%	-3.2%
IDACORP Inc.	n/a	n/a	$4.05	$4.75	4.1%	4.1%
MGE Energy	n/a	n/a	$2.40	$3.25	7.9%	7.9%
OGE Energy	3.9%	1	$1.95	$2.50	6.4%	5.2%
Otter Tail Corp.	n/a	n/a	$1.72	$2.30	7.5%	7.5%
Pinnacle West Capital	5.5%	3	$4.25	$5.25	5.4%	5.5%
PNM Resources	6.0%	2	$1.85	$2.50	7.8%	6.6%
Portland General	4.0%	3	$2.25	$3.00	7.5%	4.9%
PPL Corp.	0.0%	1	$2.05	$2.50	5.1%	2.5%
Public Serv. Enterprise	1.5%	2	$2.95	$3.25	2.5%	1.8%
Xcel Energy Inc.	6.0%	2	$2.30	$2.75	4.6%	5.5%

Sources and Notes:

[1] - [2]: Updated from ThomsonOne as of Nov 30, 2017.

[3] - [4]: From Valueline Investment Analyzer as of Nov 29, 2017.

[5]: ([4]/[3])^(1/4) - 1, where 4 is the number of years between 2021, the middle year of Value Line's 3-5 year forecast, and our study

[6]: Weighted average growth rate. If information is missing from one source, the combined growth rate depends solely on the other sour

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Most Recent Dividend [2]	Quarterly Dividend Yield (t+1) [3]	Combined Long-Term Growth Rate [4]	Quarterly Growth Rate [5]	DCF Cost of Equity [6]
ALLETE	$78.24	$0.54	0.69%	4.9%	1.2%	7.8%
Alliant Energy	$44.48	$0.32	0.72%	6.6%	1.6%	9.7%
Amer. Elec. Power	$76.55	$0.62	0.82%	3.9%	1.0%	7.3%
Ameren Corp.	$63.42	$0.44	0.70%	6.6%	1.6%	9.6%
CenterPoint Energy	$29.42	$0.27	0.92%	6.9%	1.7%	10.9%
CMS Energy Corp.	$49.69	$0.33	0.68%	7.2%	1.8%	10.1%
Consol. Edison	$87.53	$0.69	0.79%	3.1%	0.8%	6.4%
DTE Energy	$113.67	$0.83	0.73%	4.7%	1.2%	7.8%
Duke Energy	$89.25	$0.89	1.01%	3.3%	0.8%	7.4%
Edison Int'l	$80.97	$0.54	0.68%	5.7%	1.4%	8.5%
El Paso Electric	$59.69	$0.34	0.57%	5.2%	1.3%	7.6%
Entergy Corp.	$86.11	$0.89	1.03%	-3.2%	-0.8%	0.8%
IDACORP Inc.	$97.00	$0.59	0.61%	4.1%	1.0%	6.6%
MGE Energy	$65.30	$0.32	0.50%	7.9%	1.9%	10.0%
OGE Energy	$35.26	$0.33	0.96%	5.2%	1.3%	9.2%
Otter Tail Corp.	$46.59	$0.32	0.70%	7.5%	1.8%	10.5%
Pinnacle West Capital	$90.13	$0.70	0.78%	5.5%	1.3%	8.7%
PNM Resources	$44.63	$0.24	0.55%	6.6%	1.6%	8.9%
Portland General	$49.00	$0.34	0.70%	4.9%	1.2%	7.8%
PPL Corp.	$36.43	$0.40	1.09%	2.5%	0.6%	7.0%
Public Serv. Enterprise	$51.52	$0.43	0.84%	1.8%	0.4%	5.2%
Xcel Energy Inc.	$50.93	$0.36	0.72%	5.5%	1.4%	8.5%

Sources and Notes:

[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.

[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.

[3]: ([2] / [1]) x (1 + [5]).

[4]: Table No. BV-ELEC-5, [6].

[5]: {(1 + [4]) ^ (1/4)} - 1.

[6]: {([3] + [5] + 1) ^ 4} - 1.

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2017 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price [1]	Most Recent Dividend [2]	Combined Long-Term Growth Rate [3]	Growth Rate: Year 6 [4]	Growth Rate: Year 7 [5]	Growth Rate: Year 8 [6]	Growth Rate: Year 9 [7]	Growth Rate: Year 10 [8]	GDP Long-Term Growth Rate [9]	DCF Cost of Equity [10]
ALLETE	$78.24	$0.54	4.93%	4.81%	4.68%	4.56%	4.44%	4.32%	4.20%	7.2%
Alliant Energy	$44.48	$0.32	6.61%	6.21%	5.81%	5.41%	5.00%	4.60%	4.20%	7.7%
Amer. Elec. Power	$76.55	$0.62	3.87%	3.93%	3.98%	4.04%	4.09%	4.15%	4.20%	7.5%
Ameren Corp.	$63.42	$0.44	6.61%	6.21%	5.80%	5.40%	5.00%	4.60%	4.20%	7.6%
CenterPoint Energy	$29.42	$0.27	6.93%	6.48%	6.02%	5.57%	5.11%	4.66%	4.20%	8.8%
CMS Energy Corp.	$49.69	$0.33	7.22%	6.72%	6.21%	5.71%	5.21%	4.70%	4.20%	7.6%
Consol. Edison	$87.53	$0.69	3.09%	3.27%	3.46%	3.64%	3.83%	4.01%	4.20%	7.3%
DTE Energy	$113.67	$0.83	4.70%	4.61%	4.53%	4.45%	4.37%	4.28%	4.20%	7.4%
Duke Energy	$89.25	$0.89	3.26%	3.42%	3.57%	3.73%	3.89%	4.04%	4.20%	8.2%
Edison Int'l	$80.97	$0.54	5.65%	5.41%	5.17%	4.93%	4.68%	4.44%	4.20%	7.3%
El Paso Electric	$59.69	$0.34	5.25%	5.07%	4.90%	4.72%	4.55%	4.37%	4.20%	6.7%
Entergy Corp.	$86.11	$0.89	-3.24%	-2.00%	-0.76%	0.48%	1.72%	2.96%	4.20%	6.8%
IDACORP Inc.	$97.00	$0.59	4.07%	4.09%	4.11%	4.13%	4.16%	4.18%	4.20%	6.7%
MGE Energy	$65.30	$0.32	7.87%	7.26%	6.65%	6.04%	5.42%	4.81%	4.20%	6.8%
OGE Energy	$35.26	$0.33	5.15%	5.00%	4.84%	4.68%	4.52%	4.36%	4.20%	8.4%
Otter Tail Corp.	$46.59	$0.32	7.54%	6.98%	6.42%	5.87%	5.31%	4.76%	4.20%	7.8%
Pinnacle West Capital	$90.13	$0.70	5.45%	5.24%	5.03%	4.83%	4.62%	4.41%	4.20%	7.7%
PNM Resources	$44.63	$0.24	6.61%	6.21%	5.80%	5.40%	5.00%	4.60%	4.20%	6.9%
Portland General	$49.00	$0.34	4.86%	4.75%	4.64%	4.53%	4.42%	4.31%	4.20%	7.3%
PPL Corp.	$36.43	$0.40	2.53%	2.81%	3.09%	3.36%	3.64%	3.92%	4.20%	8.3%
Public Serv. Enterprise	$51.52	$0.43	1.80%	2.20%	2.60%	3.00%	3.40%	3.80%	4.20%	7.2%
Xcel Energy Inc.	$50.93	$0.36	5.52%	5.30%	5.08%	4.86%	4.64%	4.42%	4.20%	7.4%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: Table No. BV-ELEC-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: Blue Chip Economic Indicators, October 2017 U.S. This number is assumed to be the perpetual growth rate.
[10]: Supporting Schedule #3 to Table No. BV-ELEC-6.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Regulated Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Utilities Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE		BBB	-	7.8%	71.5%	-	0.0%	4.1%	28.5%	27.0%	6.45%
Alliant Energy	*	A	A	9.7%	65.1%	3.8%	1.3%	3.8%	33.7%	27.0%	7.28%
Amer. Elec. Power	*	A	-	7.3%	61.6%	-	0.0%	3.8%	38.4%	27.0%	5.56%
Ameren Corp.	*	BBB	-	9.6%	64.6%	-	0.0%	4.1%	35.4%	27.0%	7.26%
CenterPoint Energy		A	-	10.9%	58.4%	-	0.0%	3.8%	41.6%	27.0%	7.52%
CMS Energy Corp.	*	BBB	-	10.1%	57.0%	-	0.0%	4.1%	43.0%	27.0%	7.06%
Consol. Edison	*	A	-	6.4%	61.8%	-	0.0%	3.8%	38.2%	27.0%	5.01%
DTE Energy	*	BBB									
Duke Energy	*	A	-	7.4%	54.0%	-	0.0%	3.8%	46.0%	27.0%	5.31%
Edison Int'l	*	BBB	BBB	8.5%	61.5%	4.1%	5.1%	4.1%	33.4%	27.0%	6.45%
El Paso Electric	*	BBB	-	7.6%	62.4%	-	0.0%	4.1%	37.6%	27.0%	5.89%
Entergy Corp.	*	BBB	BBB	0.8%	50.5%	4.1%	0.7%	4.1%	48.9%	27.0%	~~1.90%~~
IDACORP Inc.	*	BBB	-	6.6%	72.4%	-	0.0%	4.1%	27.6%	27.0%	5.62%
MGE Energy		AA	-	10.0%	84.0%	-	0.0%	3.7%	16.0%	27.0%	8.85%
OGE Energy	*	A	-	9.2%	67.6%	-	0.0%	3.8%	32.4%	27.0%	7.11%
Otter Tail Corp.	*	BBB	-	10.5%	76.9%	-	0.0%	4.1%	23.1%	27.0%	8.78%
Pinnacle West Capital	*	A	-	8.7%	66.9%	-	0.0%	3.8%	33.1%	27.0%	6.78%
PNM Resources	*	BBB	BBB								
Portland General	*	BBB	-	7.8%	61.6%	-	0.0%	4.1%	38.4%	27.0%	5.96%
PPL Corp.	*	A	-	7.0%	51.3%	-	0.0%	3.8%	48.7%	27.0%	4.98%
Public Serv. Enterprise		BBB	-	5.2%	66.5%	-	0.0%	4.1%	33.5%	27.0%	~~4.49%~~
Xcel Energy Inc.	*	A	-	8.5%	61.7%	-	0.0%	3.8%	38.3%	27.0%	6.34%
Simple Full Sample Average				8.5%	64.5%	4.0%	0.4%	4.0%	35.2%	27.0%	6.57%
Simple Regulated Subsample Average				8.3%	63.1%	4.0%	0.4%	4.0%	36.5%	27.0%	6.36%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel A, [6].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: Effective US/Oregon Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Economic Indicators, October 2017 U.S. GDP Growth Forecast as the Perpetual Rate)

Company	Regulated Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Utilities Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE		BBB	-	7.2%	71.5%	-	0.0%	4.1%	28.5%	27.0%	6.01%
Alliant Energy	*	A	A	7.7%	65.1%	3.8%	1.3%	3.8%	33.7%	27.0%	5.99%
Amer. Elec. Power	*	A	-	7.5%	61.6%	-	0.0%	3.8%	38.4%	27.0%	5.73%
Ameren Corp.	*	BBB	-	7.6%	64.6%	-	0.0%	4.1%	35.4%	27.0%	5.98%
CenterPoint Energy		A	-	8.8%	58.4%	-	0.0%	3.8%	41.6%	27.0%	6.28%
CMS Energy Corp.	*	BBB	-	7.6%	57.0%	-	0.0%	4.1%	43.0%	27.0%	5.63%
Consol. Edison	*	A	-	7.3%	61.8%	-	0.0%	3.8%	38.2%	27.0%	5.58%
DTE Energy	*	BBB	0.00	7.4%	61.9%	NA	0.0%	4.1%	38.1%	27.0%	5.70%
Duke Energy	*	A	-	8.2%	54.0%	-	0.0%	3.8%	46.0%	27.0%	5.70%
Edison Int'l	*	BBB	BBB	7.3%	61.5%	4.1%	5.1%	4.1%	33.4%	27.0%	5.70%
El Paso Electric	*	BBB	-	6.7%	62.4%	-	0.0%	4.1%	37.6%	27.0%	5.33%
Entergy Corp.	*	BBB	BBB	6.8%	50.5%	4.1%	0.7%	4.1%	48.9%	27.0%	4.95%
IDACORP Inc.	*	BBB	-	6.7%	72.4%	-	0.0%	4.1%	27.6%	27.0%	5.71%
MGE Energy		AA	-	6.8%	84.0%	-	0.0%	3.7%	16.0%	27.0%	6.18%
OGE Energy	*	A	-	8.4%	67.6%	-	0.0%	3.8%	32.4%	27.0%	6.61%
Otter Tail Corp.	*	BBB	-	7.8%	76.9%	-	0.0%	4.1%	23.1%	27.0%	6.67%
Pinnacle West Capital	*	A	-	7.7%	66.9%	-	0.0%	3.8%	33.1%	27.0%	6.10%
PNM Resources	*	BBB	BBB	6.9%	56.6%	4.1%	0.2%	4.1%	43.2%	27.0%	5.19%
Portland General	*	BBB	-	7.3%	61.6%	-	0.0%	4.1%	38.4%	27.0%	5.62%
PPL Corp.	*	A	-	8.3%	51.3%	-	0.0%	3.8%	48.7%	27.0%	5.64%
Public Serv. Enterprise		BBB	-	7.2%	66.5%	-	0.0%	4.1%	33.5%	27.0%	5.80%
Xcel Energy Inc.	*	A	-	7.4%	61.7%	-	0.0%	3.8%	38.3%	27.0%	5.67%
Multi Full Sample Average				7.5%	63.4%	4.0%	0.3%	4.0%	36.2%	27.0%	5.8%
Multi Regulated Subsample Average				7.5%	62.0%	4.0%	0.40%	4.0%	37.6%	27.0%	5.7%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel B, [10].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: Effective US/Oregon Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points.

Table No. BV-ELEC-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	Utilities Representative Base Deemed % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Utilities Representative Income Tax Rate [4]	Utilities Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.6%	50.0%	4.1%	27.0%	50.0%	10.1%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.8%	50.0%	4.1%	27.0%	50.0%	8.6%
Regulated Subsample						
Simple DCF Quarterly	6.4%	50.0%	4.1%	27.0%	50.0%	9.7%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.7%	50.0%	4.1%	27.0%	50.0%	8.5%

Sources and Notes:

[1]: Table No. BV-ELEC-7; Panels A-B, [10].

[2]: Utilities' Assumed Capital Structure.

[3]: Based on an BBB rating. Yield from Bloomberg as of November 30, 2017.

[4]: Effective US/Oregon Corporate Tax Rate.

[5]: Utilities' Assumed Capital Structure.

[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

USING ANALYST FORECASTS FROM IBES AND VALUE LINE AND HISTORICAL GDP GROWTH FROM 1990 TO 2016 AS LONG-TERM GDP GROWTH

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel B: Using Analyst Forecasts and Historic GDP Growth for 1990-2016

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	$78.24	$0.54	4.93%	4.86%	4.80%	4.73%	4.67%	4.60%	4.54%	7.5%
Alliant Energy	$44.48	$0.32	6.61%	6.27%	5.92%	5.58%	5.23%	4.89%	4.54%	8.0%
Amer. Elec. Power	$76.55	$0.62	3.87%	3.98%	4.09%	4.21%	4.32%	4.43%	4.54%	7.8%
Ameren Corp.	$63.42	$0.44	6.61%	6.26%	5.92%	5.57%	5.23%	4.88%	4.54%	7.9%
CenterPoint Energy	$29.42	$0.27	6.93%	6.53%	6.14%	5.74%	5.34%	4.94%	4.54%	9.0%
CMS Energy Corp.	$49.69	$0.33	7.22%	6.77%	6.33%	5.88%	5.43%	4.99%	4.54%	7.9%
Consol. Edison	$87.53	$0.69	3.09%	3.33%	3.57%	3.81%	4.06%	4.30%	4.54%	7.6%
DTE Energy	$113.67	$0.83	4.70%	4.67%	4.64%	4.62%	4.59%	4.57%	4.54%	7.6%
Duke Energy	$89.25	$0.89	3.26%	3.48%	3.69%	3.90%	4.11%	4.33%	4.54%	8.4%
Edison Int'l	$80.97	$0.54	5.65%	5.47%	5.28%	5.10%	4.91%	4.73%	4.54%	7.6%
El Paso Electric	$59.69	$0.34	5.25%	5.13%	5.01%	4.89%	4.78%	4.66%	4.54%	7.0%
Entergy Corp.	$86.11	$0.89	-3.24%	-1.95%	-0.65%	0.65%	1.95%	3.24%	4.54%	7.1%
IDACORP Inc.	$97.00	$0.59	4.07%	4.15%	4.22%	4.30%	4.38%	4.46%	4.54%	7.0%
MGE Energy	$65.30	$0.32	7.87%	7.32%	6.76%	6.21%	5.65%	5.10%	4.54%	7.1%
OGE Energy	$35.26	$0.33	5.15%	5.05%	4.95%	4.85%	4.74%	4.64%	4.54%	8.7%
Otter Tail Corp.	$46.59	$0.32	7.54%	7.04%	6.54%	6.04%	5.54%	5.04%	4.54%	8.1%
Pinnacle West Capital	$90.13	$0.70	5.45%	5.30%	5.15%	5.00%	4.84%	4.69%	4.54%	8.0%
PNM Resources	$44.63	$0.24	6.61%	6.26%	5.92%	5.57%	5.23%	4.88%	4.54%	7.2%
Portland General	$49.00	$0.34	4.86%	4.81%	4.76%	4.70%	4.65%	4.59%	4.54%	7.5%
PPL Corp.	$36.43	$0.40	2.53%	2.86%	3.20%	3.53%	3.87%	4.20%	4.54%	8.6%
Public Serv. Enterprise	$51.52	$0.43	1.80%	2.26%	2.72%	3.17%	3.63%	4.08%	4.54%	7.5%
Xcel Energy Inc.	$50.93	$0.36	5.52%	5.35%	5.19%	5.03%	4.87%	4.70%	4.54%	7.7%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: Table No. BV-ELEC-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: Blue Chip Economic Indicators, October 2017 U.S. This number is assumed to be the perpetual growth rate.
[10]: Supporting Schedule #3 to Table No. BV-ELEC-6.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel B: Using Analyst Forecasts and Historic GDP Growth for 1990-2016

Company	Regulated Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Utilities Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE		BBB	-	7.5%	71.5%	-	0.0%	4.1%	28.5%	27.0%	6.22%
Alliant Energy	*	A	A	8.0%	65.1%	3.8%	1.3%	3.8%	33.7%	27.0%	6.17%
Amer. Elec. Power	*	A	-	7.8%	61.6%	-	0.0%	3.8%	38.4%	27.0%	5.90%
Ameren Corp.	*	BBB	-	7.9%	64.6%	-	0.0%	4.1%	35.4%	27.0%	6.16%
CenterPoint Energy		A	-	9.0%	58.4%	-	0.0%	3.8%	41.6%	27.0%	6.43%
CMS Energy Corp.	*	BBB	-	7.9%	57.0%	-	0.0%	4.1%	43.0%	27.0%	5.79%
Consol. Edison	*	A	-	7.6%	61.8%	-	0.0%	3.8%	38.2%	27.0%	5.75%
DTE Energy	*	BBB	0.00	7.6%	61.9%	NA	0.0%	4.1%	38.1%	27.0%	5.87%
Duke Energy	*	A	-	8.4%	54.0%	-	0.0%	3.8%	46.0%	27.0%	5.85%
Edison Int'l	*	BBB	BBB	7.6%	61.5%	4.1%	5.1%	4.1%	33.4%	27.0%	5.87%
El Paso Electric	*	BBB	-	7.0%	62.4%	-	0.0%	4.1%	37.6%	27.0%	5.51%
Entergy Corp.	*	BBB	BBB	7.1%	50.5%	4.1%	0.7%	4.1%	48.9%	27.0%	5.09%
IDACORP Inc.	*	BBB	-	7.0%	72.4%	-	0.0%	4.1%	27.6%	27.0%	5.92%
MGE Energy		AA	-	7.1%	84.0%	-	0.0%	3.7%	16.0%	27.0%	6.42%
OGE Energy	*	A	-	8.7%	67.6%	-	0.0%	3.8%	32.4%	27.0%	6.79%
Otter Tail Corp.	*	BBB	-	8.1%	76.9%	-	0.0%	4.1%	23.1%	27.0%	6.88%
Pinnacle West Capital	*	A	-	8.0%	66.9%	-	0.0%	3.8%	33.1%	27.0%	6.28%
PNM Resources	*	BBB	BBB	7.2%	56.6%	4.1%	0.2%	4.1%	43.2%	27.0%	5.36%
Portland General	*	BBB	-	7.5%	61.6%	-	0.0%	4.1%	38.4%	27.0%	5.79%
PPL Corp.	*	A	-	8.6%	51.3%	-	0.0%	3.8%	48.7%	27.0%	5.78%
Public Serv. Enterprise		BBB	-	7.5%	66.5%	-	0.0%	4.1%	33.5%	27.0%	5.98%
Xcel Energy Inc.	*	A	-	7.7%	61.7%	-	0.0%	3.8%	38.3%	27.0%	5.84%
Multi Full Sample Average				7.8%	63.4%	4.0%	0.3%	4.0%	36.2%	27.0%	6.0%
Multi Regulated Subsample Average				7.8%	62.0%	4.0%	0.40%	4.0%	37.6%	27.0%	5.9%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel B, [10].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: Effective US/Oregon Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points.

Table No. BV-ELEC-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	Utilities Representative Base Deemed % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Utilities Representative Income Tax Rate [4]	Utilities Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.6%	50.0%	4.1%	27.0%	50.0%	10.1%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	6.0%	50.0%	4.1%	27.0%	50.0%	9.0%
Regulated Subsample						
Simple DCF Quarterly	6.4%	50.0%	4.1%	27.0%	50.0%	9.7%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	5.9%	50.0%	4.1%	27.0%	50.0%	8.8%

Sources and Notes:
[1]: Table No. BV-ELEC-7; Panels A-B, [10].
[2]: Utilities' Assumed Capital Structure.
[3]: Based on an BBB rating. Yield from Bloomberg as of November 30, 2017.
[4]: Effective US/Oregon Corporate Tax Rate.
[5]: Utilities' Assumed Capital Structure.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

USING ANALYST FORECASTS FROM IBES AND VALUE LINE AND HISTORICAL GDP GROWTH FROM 1947 TO 2016 AS LONG-TERM GDP GROWTH

Table No. BV-ELEC-6

DCF Cost of Equity of the U.S. Electric Sample

Panel B: Using Analysts Forecasts and Historic GDP Growth 1947-2016

Company	Stock Price [1]	Most Recent Dividend [2]	Combined Long-Term Growth Rate [3]	Growth Rate: Year 6 [4]	Growth Rate: Year 7 [5]	Growth Rate: Year 8 [6]	Growth Rate: Year 9 [7]	Growth Rate: Year 10 [8]	GDP Long-Term Growth Rate [9]	DCF Cost of Equity [10]
ALLETE	$78.24	$0.54	4.93%	5.19%	5.45%	5.72%	5.98%	6.25%	6.51%	9.2%
Alliant Energy	$44.48	$0.32	6.61%	6.60%	6.58%	6.56%	6.54%	6.53%	6.51%	9.6%
Amer. Elec. Power	$76.55	$0.62	3.87%	4.31%	4.75%	5.19%	5.63%	6.07%	6.51%	9.5%
Ameren Corp.	$63.42	$0.44	6.61%	6.59%	6.57%	6.56%	6.54%	6.53%	6.51%	9.5%
CenterPoint Energy	$29.42	$0.27	6.93%	6.86%	6.79%	6.72%	6.65%	6.58%	6.51%	10.5%
CMS Energy Corp.	$49.69	$0.33	7.22%	7.10%	6.98%	6.87%	6.75%	6.63%	6.51%	9.5%
Consol. Edison	$87.53	$0.69	3.09%	3.66%	4.23%	4.80%	5.37%	5.94%	6.51%	9.2%
DTE Energy	$113.67	$0.83	4.70%	5.00%	5.30%	5.60%	5.91%	6.21%	6.51%	9.3%
Duke Energy	$89.25	$0.89	3.26%	3.80%	4.34%	4.89%	5.43%	5.97%	6.51%	10.0%
Edison Int'l	$80.97	$0.54	5.65%	5.80%	5.94%	6.08%	6.22%	6.37%	6.51%	9.2%
El Paso Electric	$59.69	$0.34	5.25%	5.46%	5.67%	5.88%	6.09%	6.30%	6.51%	8.7%
Entergy Corp.	$86.11	$0.89	-3.24%	-1.62%	0.01%	1.63%	3.26%	4.88%	6.51%	8.8%
IDACORP Inc.	$97.00	$0.59	4.07%	4.47%	4.88%	5.29%	5.70%	6.10%	6.51%	8.7%
MGE Energy	$65.30	$0.32	7.87%	7.65%	7.42%	7.19%	6.96%	6.74%	6.51%	8.8%
OGE Energy	$35.26	$0.33	5.15%	5.38%	5.61%	5.83%	6.06%	6.28%	6.51%	10.3%
Otter Tail Corp.	$46.59	$0.32	7.54%	7.36%	7.19%	7.02%	6.85%	6.68%	6.51%	9.7%
Pinnacle West Capital	$90.13	$0.70	5.45%	5.63%	5.80%	5.98%	6.16%	6.33%	6.51%	9.6%
PNM Resources	$44.63	$0.24	6.61%	6.59%	6.57%	6.56%	6.54%	6.53%	6.51%	8.9%
Portland General	$49.00	$0.34	4.86%	5.14%	5.41%	5.69%	5.96%	6.24%	6.51%	9.2%
PPL Corp.	$36.43	$0.40	2.53%	3.19%	3.86%	4.52%	5.18%	5.85%	6.51%	10.2%
Public Serv. Enterprise	$51.52	$0.43	1.80%	2.59%	3.37%	4.16%	4.94%	5.73%	6.51%	9.2%
Xcel Energy Inc.	$50.93	$0.36	5.52%	5.68%	5.85%	6.01%	6.18%	6.34%	6.51%	9.4%

Sources and Notes:
[1]: Supporting Schedule #1 to Table No. BV-ELEC-6.
[2]: Supporting Schedule #2 to Table No. BV-ELEC-6.
[3]: Table No. BV-ELEC-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: Blue Chip Economic Indicators, October 2017 U.S. This number is assumed to be the perpetual growth rate.
[10]: Supporting Schedule #3 to Table No. BV-ELEC-6.

Table No. BV-ELEC-7

Overall After-Tax DCF Cost of Capital of the U.S. Electric Sample

Panel B: Using Analysts Forecasts and Historic GDP Growth 1947-2016

Company	Regulated Subsample	3rd Quarter, 2017 Bond Rating [1]	3rd Quarter, 2017 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Utilities Representative Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE		BBB	-	9.2%	71.5%	-	0.0%	4.1%	28.5%	27.0%	7.40%
Alliant Energy	*	A	A	9.6%	65.1%	3.8%	1.3%	3.8%	33.7%	27.0%	7.23%
Amer. Elec. Power	*	A	-	9.5%	61.6%	-	0.0%	3.8%	38.4%	27.0%	6.90%
Ameren Corp.	*	BBB	-	9.5%	64.6%	-	0.0%	4.1%	35.4%	27.0%	7.21%
CenterPoint Energy		A	-	10.5%	58.4%	-	0.0%	3.8%	41.6%	27.0%	7.32%
CMS Energy Corp.	*	BBB	-	9.5%	57.0%	-	0.0%	4.1%	43.0%	27.0%	6.72%
Consol. Edison	*	A	-	9.2%	61.8%	-	0.0%	3.8%	38.2%	27.0%	6.77%
DTE Energy	*	BBB	0.00	9.3%	61.9%	NA	0.0%	4.1%	38.1%	27.0%	6.89%
Duke Energy	*	A	-	10.0%	54.0%	-	0.0%	3.8%	46.0%	27.0%	6.70%
Edison Int'l	*	BBB	BBB	9.2%	61.5%	4.1%	5.1%	4.1%	33.4%	27.0%	6.89%
El Paso Electric	*	BBB	-	8.7%	62.4%	-	0.0%	4.1%	37.6%	27.0%	6.58%
Entergy Corp.	*	BBB	BBB	8.8%	50.5%	4.1%	0.7%	4.1%	48.9%	27.0%	5.95%
IDACORP Inc.	*	BBB	-	8.7%	72.4%	-	0.0%	4.1%	27.6%	27.0%	7.15%
MGE Energy		AA	-	8.8%	84.0%	-	0.0%	3.7%	16.0%	27.0%	7.85%
OGE Energy	*	A	-	10.3%	67.6%	-	0.0%	3.8%	32.4%	27.0%	7.84%
Otter Tail Corp.	*	BBB	-	9.7%	76.9%	-	0.0%	4.1%	23.1%	27.0%	8.13%
Pinnacle West Capital	*	A	-	9.6%	66.9%	-	0.0%	3.8%	33.1%	27.0%	7.36%
PNM Resources	*	BBB	BBB	8.9%	56.6%	4.1%	0.2%	4.1%	43.2%	27.0%	6.31%
Portland General	*	BBB	-	9.2%	61.6%	-	0.0%	4.1%	38.4%	27.0%	6.81%
PPL Corp.	*	A	-	10.2%	51.3%	-	0.0%	3.8%	48.7%	27.0%	6.58%
Public Serv. Enterprise		BBB	-	9.2%	66.5%	-	0.0%	4.1%	33.5%	27.0%	7.09%
Xcel Energy Inc.	*	A	-	9.4%	61.7%	-	0.0%	3.8%	38.3%	27.0%	6.85%
Multi Full Sample Average				9.4%	63.4%	4.0%	0.3%	4.0%	36.2%	27.0%	7.0%
Multi Regulated Subsample Average				9.4%	62.0%	4.0%	0.40%	4.0%	37.6%	27.0%	6.9%

Sources and Notes:
[1]: S&P Credit Ratings from Research Insight.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. BV-ELEC-6; Panel B, [10].
[4]: Table No. BV-ELEC-4, [1].
[5]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[6]: Table No. BV-ELEC-4, [2].
[7]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel B.
[8]: Table No. BV-ELEC-4, [3].
[9]: Effective US/Oregon Corporate Tax Rate.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points.

Table No. BV-ELEC-8

DCF Cost of Equity at Representative Deemed Capital Structure

	Overall After -Tax Cost of Capital [1]	Utilities Representative Base Deemed % Debt [2]	Representative Cost of BBB Rated Utility Debt [3]	Utilities Representative Income Tax Rate [4]	Utilities Representative Base Deemed % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.6%	50.0%	4.1%	27.0%	50.0%	10.1%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	7.0%	50.0%	4.1%	27.0%	50.0%	11.1%
Regulated Subsample						
Simple DCF Quarterly	6.4%	50.0%	4.1%	27.0%	50.0%	9.7%
Multi-Stage DCF - Using Long-Term GDP Growth Forecast as the Perpetual Rate	6.9%	50.0%	4.1%	27.0%	50.0%	10.9%

Sources and Notes:
[1]: Table No. BV-ELEC-7; Panels A-B, [10].
[2]: Utilities' Assumed Capital Structure.
[3]: Based on an BBB rating. Yield from Bloomberg as of November 30, 2017.
[4]: Effective US/Oregon Corporate Tax Rate.
[5]: Utilities' Assumed Capital Structure.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

RISK PREMIUM MODEL

Risk Premium Model Cost of Equity Inputs

Input	Value
Forecasted 10-Year Government Bond Rate Source: October 2017 Blue Chip Forcast for 2019.	3.4%
Historical Average 10Y to 20Y Maturity Premium Source: Bloomberg.	0.50%
Utility Yield Spread Adjustment	0.20%
Case Type	Vertically Integrated

Risk Premiums Determined by Relationship Between Authorized ROEs[1] and Long-term Treasury Bond Rates During the Period 1990-2017

Formula: Risk Premium = A_0 + (A_1 x Treasury bond Rate)

R Squared		0.8362				
Estimate of intercept (A_0)		8.787%				
Estimate of slope (A_1)		-0.5810				
Equity Cost Estimate for Vertically Integrated Electric		Predicted Risk Premium		Expected Treasury Bond Rate[2]		
10.5%	=	6.40%	+	4.10%	[3]	
10.4%	=	6.52%	+	3.90%	[4]	

Sources and Notes:

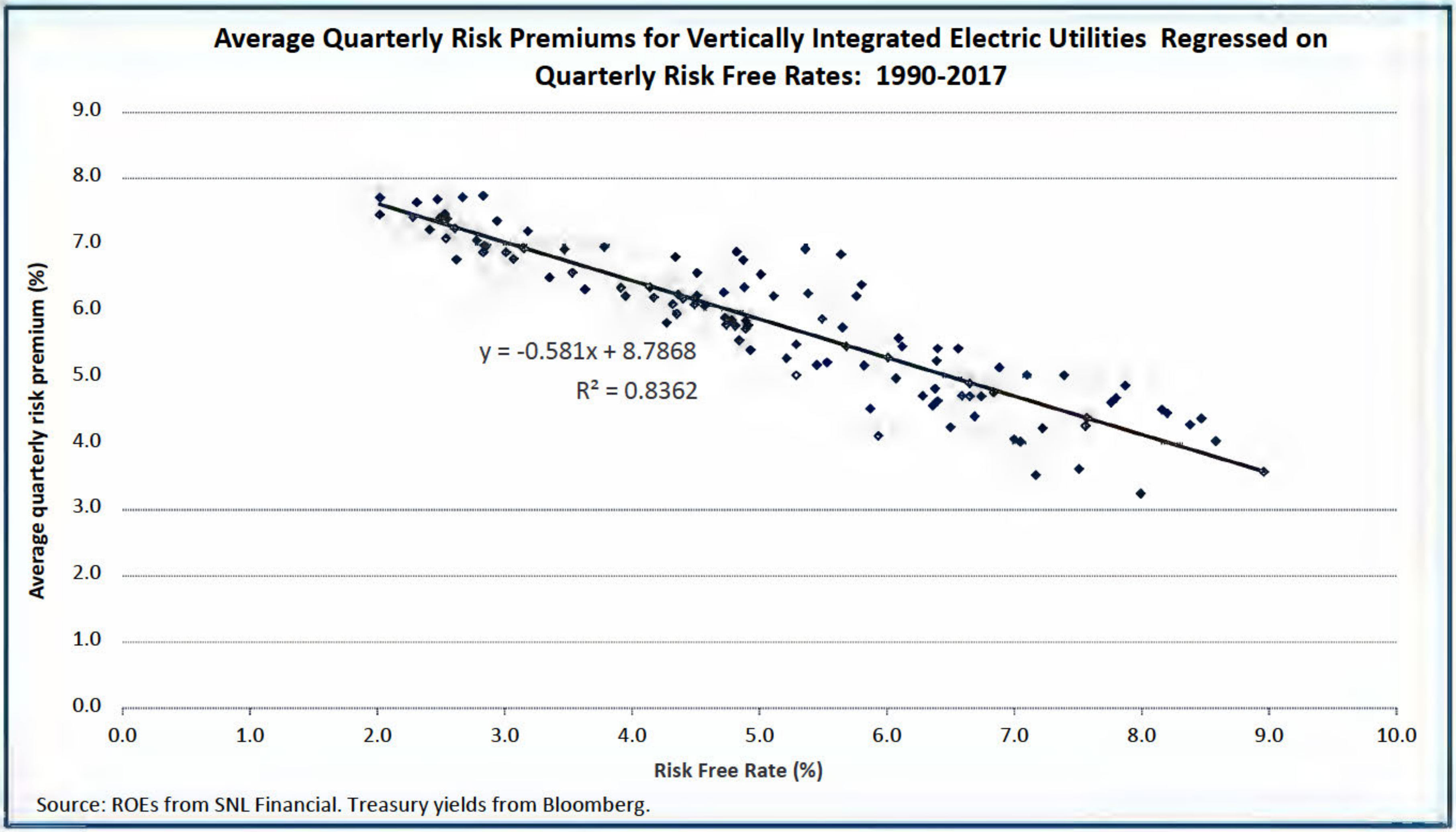
[1]: Authorized ROE Data sourced from SNL Financial.

[2]: Blue Chip consensus forecast 2019 10-yr T-bill Yield plus maturity premium

[3]: Estimate with expected treasury bond rate normalized with 0.20% utility yield spread adjustment

[4]: Estimate without treasury bond rate normalization.

See regression results for derivation of regression coefficients A_0 and A_1.


Average Quarterly Risk Premiums for Vertically Integrated Electric Utilities Regressed on Quarterly Risk Free Rates: 1990-2017
y = -0.581x + 8.7868
R² = 0.8362
Average quarterly risk premium (%)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.0
Risk Free Rate (%)
Source: ROEs from SNL Financial. Treasury yields from Bloomberg.

CAPITAL ASSET PRICING MODEL

Table No. BV-ELEC-9

Risk Free Rate

[1]	Blue Chip 10-Year Forecast	3.40%
	US Government Bond Yields	
[2]	20-year	5.04%
[3]	10-Year	4.52%
[4]	Maturity Premium	0.52%
[5]	Blue Chip 10-Year Forecast Adjusted to 20-year Horizon	3.92%

Sources and Notes:

[1]: Blue Chip Economic Indicators, October 2017 U.S.

[2]-[3]: Supporting Schedule # 1 to Table No. BV-ELEC-9. Averages of monthly bond yields from December 1990 through November 2017.

[4]: [2] - [3].

[5]: [1] + [4].

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Regulated Subsample	Long-Term Risk-Free Rate [1]	ValueLine Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE		4.12%	0.75	6.94%	9.3%	9.7%
Alliant Energy	*	4.12%	0.70	6.94%	9.0%	9.4%
Amer. Elec. Power	*	4.12%	0.65	6.94%	8.6%	9.2%
Ameren Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
CenterPoint Energy		4.12%	0.90	6.94%	10.4%	10.5%
CMS Energy Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
Consol. Edison	*	4.12%	0.50	6.94%	7.6%	8.3%
DTE Energy						
Duke Energy	*	4.12%	0.60	6.94%	8.3%	8.9%
Edison Int'l	*	4.12%	0.65	6.94%	8.6%	9.2%
El Paso Electric	*	4.12%	0.80	6.94%	9.7%	10.0%
Entergy Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
IDACORP Inc.	*	4.12%	0.70	6.94%	9.0%	9.4%
MGE Energy		4.12%	0.75	6.94%	9.3%	9.7%
OGE Energy	*	4.12%	0.95	6.94%	10.7%	10.8%
Otter Tail Corp.	*	4.12%	0.90	6.94%	10.4%	10.5%
Pinnacle West Capital	*	4.12%	0.70	6.94%	9.0%	9.4%
PNM Resources						
Portland General	*	4.12%	0.70	6.94%	9.0%	9.4%
PPL Corp.	*	4.12%	0.70	6.94%	9.0%	9.4%
Public Serv. Enterprise		4.12%	0.70	6.94%	9.0%	9.4%
Xcel Energy Inc.	*	4.12%	0.60	6.94%	8.3%	8.9%
Average					9.0%	9.5%
Regulated Subsample Average					8.9%	9.4%

Sources and Notes:

[1]: Villadsen Direct Evidence.

[2]: Bloomberg as of November 30, 2017.

[3]: Villadsen Direct Evidence.

[4]: [1] + ([2] x [3]).

[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Regulated Subsample	Long-Term Risk-Free Rate [1]	ValueLine Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE		3.92%	0.75	7.44%	9.5%	9.9%
Alliant Energy	*	3.92%	0.70	7.44%	9.1%	9.6%
Amer. Elec. Power	*	3.92%	0.65	7.44%	8.8%	9.3%
Ameren Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
CenterPoint Energy		3.92%	0.90	7.44%	10.6%	10.8%
CMS Energy Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
Consol. Edison	*	3.92%	0.50	7.44%	7.6%	8.4%
DTE Energy						
Duke Energy	*	3.92%	0.60	7.44%	8.4%	9.0%
Edison Int'l	*	3.92%	0.65	7.44%	8.8%	9.3%
El Paso Electric	*	3.92%	0.80	7.44%	9.9%	10.2%
Entergy Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
IDACORP Inc.	*	3.92%	0.70	7.44%	9.1%	9.6%
MGE Energy		3.92%	0.75	7.44%	9.5%	9.9%
OGE Energy	*	3.92%	0.95	7.44%	11.0%	11.1%
Otter Tail Corp.	*	3.92%	0.90	7.44%	10.6%	10.8%
Pinnacle West Capital	*	3.92%	0.70	7.44%	9.1%	9.6%
PNM Resources						
Portland General	*	3.92%	0.70	7.44%	9.1%	9.6%
PPL Corp.	*	3.92%	0.70	7.44%	9.1%	9.6%
Public Serv. Enterprise		3.92%	0.70	7.44%	9.1%	9.6%
Xcel Energy Inc.	*	3.92%	0.60	7.44%	8.4%	9.0%
Average					9.2%	9.6%
Regulated Subsample Average					9.1%	9.5%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Bloomberg as of November 30, 2017.
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Regulated Subsample	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted- Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	Utilities Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE		9.3%	9.7%	61.8%	-	0.0%	4.10%	38.2%	27.0%	6.9%	7.1%
Alliant Energy	*	9.0%	9.4%	59.9%	3.85%	1.8%	3.85%	38.3%	27.0%	6.5%	6.8%
Amer. Elec. Power	*	8.6%	9.2%	55.4%	-	0.0%	4.05%	44.6%	27.0%	6.1%	6.4%
Ameren Corp.	*	8.6%	9.2%	57.4%	-	0.0%	4.10%	42.6%	27.0%	6.2%	6.5%
CenterPoint Energy		10.4%	10.5%	51.0%	-	0.0%	3.85%	49.0%	27.0%	6.7%	6.7%
CMS Energy Corp.	*	8.6%	9.2%	48.5%	-	0.0%	4.10%	51.5%	27.0%	5.7%	6.0%
Consol. Edison	*	7.6%	8.3%	57.7%	-	0.0%	3.85%	42.3%	27.0%	5.6%	6.0%
DTE Energy											
Duke Energy	*	8.3%	8.9%	52.8%	-	0.0%	3.95%	47.2%	27.0%	5.7%	6.0%
Edison Int'l	*	8.6%	9.2%	55.4%	4.10%	5.7%	4.10%	38.9%	27.0%	6.2%	6.5%
El Paso Electric	*	9.7%	10.0%	56.1%	-	0.0%	4.10%	43.9%	27.0%	6.7%	6.9%
Entergy Corp.	*	8.6%	9.2%	48.0%	4.10%	1.0%	4.10%	51.0%	27.0%	5.7%	6.0%
IDACORP Inc.	*	9.0%	9.4%	62.2%	-	0.0%	4.10%	37.8%	27.0%	6.7%	7.0%
MGE Energy		9.3%	9.7%	77.0%	-	0.0%	3.72%	23.0%	27.0%	7.8%	8.1%
OGE Energy	*	10.7%	10.8%	68.1%	-	0.0%	3.85%	31.9%	27.0%	8.2%	8.2%
Otter Tail Corp.	*	10.4%	10.5%	66.5%	-	0.1%	4.10%	33.4%	27.0%	7.9%	8.0%
Pinnacle West Capital	*	9.0%	9.4%	62.8%	-	0.0%	3.90%	37.2%	27.0%	6.7%	7.0%
PNM Resources											
Portland General	*	9.0%	9.4%	54.3%	-	0.0%	4.10%	45.7%	27.0%	6.2%	6.5%
PPL Corp.	*	9.0%	9.4%	47.7%	-	0.0%	3.95%	52.3%	27.0%	5.8%	6.0%
Public Serv. Enterprise		9.0%	9.4%	65.0%	-	0.0%	4.10%	35.0%	27.0%	6.9%	7.2%
Xcel Energy Inc.	*	8.3%	8.9%	55.1%	-	0.0%	3.85%	44.9%	27.0%	5.8%	6.2%
Full Sample Average		9.0%	9.5%	58.1%	4.0%	0.4%	4.0%	41.4%	27.0%	6.5%	6.8%
Regulated Subsample Average		8.9%	9.4%	56.7%	4.0%	0.5%	4.0%	42.7%	27.0%	6.4%	6.6%

Sources and Notes:

[1]: Table No. BV-ELEC-10; Panel A, [4].
[2]: Table No. BV-ELEC-10; Panel A, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: Effective US/Oregon Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Regulated Subsample	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	Utilities Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE		9.5%	9.9%	61.8%	-	0.0%	4.10%	38.2%	27.0%	7.0%	7.2%
Alliant Energy	*	9.1%	9.6%	59.9%	3.85%	1.8%	3.85%	38.3%	27.0%	6.6%	6.9%
Amer. Elec. Power	*	8.8%	9.3%	55.4%	-	0.0%	4.05%	44.6%	27.0%	6.2%	6.5%
Ameren Corp.	*	8.8%	9.3%	57.4%	-	0.0%	4.10%	42.6%	27.0%	6.3%	6.6%
CenterPoint Energy		10.6%	10.8%	51.0%	-	0.0%	3.85%	49.0%	27.0%	6.8%	6.9%
CMS Energy Corp.	*	8.8%	9.3%	48.5%	-	0.0%	4.10%	51.5%	27.0%	5.8%	6.0%
Consol. Edison	*	7.6%	8.4%	57.7%	-	0.0%	3.85%	42.3%	27.0%	5.6%	6.0%
DTE Energy											
Duke Energy	*	8.4%	9.0%	52.8%	-	0.0%	3.95%	47.2%	27.0%	5.8%	6.1%
Edison Int'l	*	8.8%	9.3%	55.4%	4.10%	5.7%	4.10%	38.9%	27.0%	6.2%	6.5%
El Paso Electric	*	9.9%	10.2%	56.1%	-	0.0%	4.10%	43.9%	27.0%	6.9%	7.0%
Entergy Corp.	*	8.8%	9.3%	48.0%	4.10%	1.0%	4.10%	51.0%	27.0%	5.8%	6.0%
IDACORP Inc.	*	9.1%	9.6%	62.2%	-	0.0%	4.10%	37.8%	27.0%	6.8%	7.1%
MGE Energy		9.5%	9.9%	77.0%	-	0.0%	3.72%	23.0%	27.0%	7.9%	8.2%
OGE Energy	*	11.0%	11.1%	68.1%	-	0.0%	3.85%	31.9%	27.0%	8.4%	8.4%
Otter Tail Corp.	*	10.6%	10.8%	66.5%	-	0.1%	4.10%	33.4%	27.0%	8.1%	8.2%
Pinnacle West Capital	*	9.1%	9.6%	62.8%	-	0.0%	3.90%	37.2%	27.0%	6.8%	7.1%
PNM Resources											
Portland General	*	9.1%	9.6%	54.3%	-	0.0%	4.10%	45.7%	27.0%	6.3%	6.6%
PPL Corp.	*	9.1%	9.6%	47.7%	-	0.0%	3.95%	52.3%	27.0%	5.9%	6.1%
Public Serv. Enterprise		9.1%	9.6%	65.0%	-	0.0%	4.10%	35.0%	27.0%	7.0%	7.3%
Xcel Energy Inc.	*	8.4%	9.0%	55.1%	-	0.0%	3.85%	44.9%	27.0%	5.9%	6.2%
Full Sample Average		9.2%	9.6%	58.1%	4.0%	0.4%	4.0%	41.4%	27.0%	6.6%	6.8%
Regulated Subsample Average		9.1%	9.5%	56.7%	4.0%	0.5%	4.0%	42.7%	27.0%	6.5%	6.7%

Sources and Notes:

[1]: Table No. BV-ELEC-10; Panel B, [4].
[2]: Table No. BV-ELEC-10; Panel B, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: Effective US/Oregon Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points

Table No. BV-ELEC-12

Risk Positioning Cost of Equity at Representative Deemed Capital Structure

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	Utilities Representative Base Deemed % Debt	Representative Cost of BBB-Rated Utility Debt	Utilities Representative Income Tax Rate	Utilities Representative Base Deemed % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Full Sample:								
CAPM	6.5%	6.6%	50.0%	4.1%	27.0%	50.0%	10.0%	10.2%
ECAPM (1.50%)	6.8%	6.8%	50.0%	4.1%	27.0%	50.0%	10.5%	10.7%
Regulated Subsample:								
CAPM	6.4%	6.5%	50.0%	4.1%	27.0%	50.0%	9.7%	9.9%
ECAPM (1.50%)	6.6%	6.7%	50.0%	4.1%	27.0%	50.0%	10.2%	10.4%

Sources and Notes:

[1]: Table No. BV-ELEC-11; Panel A, [9] - [10].

[2]: Table No. BV-ELEC-11; Panel B, [9] - [10].

Scenario 1: Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%.

Scenario 2: Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%.

[3]: Utilities' Assumed Capital Structure.

[4]: Based on a BBB rating. Yield from Bloomberg as of November 30, 2017.

[5]: Effective US/Oregon Corporate Tax Rate.

[6]: Utilities' Assumed Capital Structure.

[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6].

[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6].

Table No. BV-ELEC-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company	Regulated Subsample	ValueLine Betas [1]	Debt Beta [2]	5-Year Average Common Equity to Market Value Ratio [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	5-Year Average Debt to Market Value Ratio [5]	Utilities Representative Income Tax Rate [6]	Asset Beta: Without Taxes [7]	Asset Beta: With Taxes [8]
ALLETE		0.75	0.10	61.8%	0.0%	38.2%	27.0%	0.50	0.55
Alliant Energy	*	0.70	0.05	59.9%	1.8%	38.3%	27.0%	0.44	0.48
Amer. Elec. Power	*	0.65	0.09	55.4%	0.0%	44.6%	27.0%	0.40	0.44
Ameren Corp.	*	0.65	0.10	57.4%	0.0%	42.6%	27.0%	0.42	0.46
CenterPoint Energy		0.90	0.05	51.0%	0.0%	49.0%	27.0%	0.48	0.55
CMS Energy Corp.	*	0.65	0.10	48.5%	0.0%	51.5%	27.0%	0.37	0.41
Consol. Edison	*	0.50	0.05	57.7%	0.0%	42.3%	27.0%	0.31	0.34
DTE Energy									
Duke Energy	*	0.60	0.07	52.8%	0.0%	47.2%	27.0%	0.35	0.39
Edison Int'l	*	0.65	0.10	55.4%	5.7%	38.9%	27.0%	0.40	0.44
El Paso Electric	*	0.80	0.10	56.1%	0.0%	43.9%	27.0%	0.49	0.55
Entergy Corp.	*	0.65	0.10	48.0%	1.0%	51.0%	27.0%	0.36	0.41
IDACORP Inc.	*	0.70	0.10	62.2%	0.0%	37.8%	27.0%	0.47	0.52
MGE Energy		0.75	0.05	77.0%	0.0%	23.0%	27.0%	0.59	0.62
OGE Energy	*	0.95	0.05	68.1%	0.0%	31.9%	27.0%	0.66	0.72
Otter Tail Corp.	*	0.90	0.10	66.5%	0.1%	33.4%	27.0%	0.63	0.68
Pinnacle West Capital	*	0.70	0.06	62.8%	0.0%	37.2%	27.0%	0.46	0.51
PNM Resources									
Portland General	*	0.70	0.10	54.3%	0.0%	45.7%	27.0%	0.43	0.47
PPL Corp.	*	0.70	0.10	47.7%	0.0%	52.3%	27.0%	0.39	0.43
Public Serv. Enterprise		0.70	0.07	65.0%	0.0%	35.0%	27.0%	0.48	0.52
Xcel Energy Inc.	*	0.60	0.10	55.1%	0.0%	44.9%	27.0%	0.38	0.41
Full Sample Average		0.71	0.08	58.1%	0.4%	41.4%	27.0%	0.45	0.50
Regulated Subsample Average		0.69	0.09	56.7%	0.5%	42.7%	27.0%	0.43	0.48

Sources and Notes:
[1]: Supporting Schedule # 1 to Table No. BV-ELEC-10, [1].
[2]: Supporting Schedule #1 to Table No. BV-ELEC-13, [7].
[3]: Table No. BV-ELEC-4, [4].
[4]: Table No. BV-ELEC-4, [5].
[5]: Table No. BV-ELEC-4, [6].
[6]: Effective US/Oregon Corporate Tax Rate
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Table No. BV-ELEC-14

Sample Average Asset Beta Relevered at Representative Deemed Capital Structure

	Asset Beta [1]	Assumed Debt Beta [2]	Utilities Representative Base Deemed % Debt [3]	Utilities Representative Income Tax Rate [4]	Utilities Representative Base Deemed % Equity [5]	Estimated Equity Beta [6]
Full Sample:						
Asset Beta Without Taxes	0.45	0.05	50.0%	27.0%	50.0%	0.85
Asset Beta With Taxes	0.50	0.05	50.0%	27.0%	50.0%	0.82
Regulated Subsample:						
Asset Beta Without Taxes	0.43	0.05	50.0%	27.0%	50.0%	0.82
Asset Beta With Taxes	0.48	0.05	50.0%	27.0%	50.0%	0.79

Sources and Notes:

[1]: Table No. BV-ELEC-13, [7] - [8].

[2]: Debt Beta estimate for BBB rated entities. Corporate Finance, Berk and Demarzo, Second Edition, p. 389.

[3]: Utilities' Assumed Capital Structure.

[4]: Effective US/Oregon Corporate Tax Rate.

[5]: Utilities' Assumed Capital Structure.

[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:					
Asset Beta Without Taxes	4.12%	0.85	6.94%	10.0%	10.2%
Asset Beta With Taxes	4.12%	0.82	6.94%	9.8%	10.1%
Regulated Subsample:					
Asset Beta Without Taxes	4.12%	0.82	6.94%	9.8%	10.1%
Asset Beta With Taxes	4.12%	0.79	6.94%	9.6%	9.9%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:					
Asset Beta Without Taxes	3.92%	0.85	7.44%	10.3%	10.5%
Asset Beta With Taxes	3.92%	0.82	7.44%	10.0%	10.3%
Regulated Subsample:					
Asset Beta Without Taxes	3.92%	0.82	7.44%	10.0%	10.3%
Asset Beta With Taxes	3.92%	0.79	7.44%	9.8%	10.1%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is the review of regulatory practices regarding the return on equity, capital structure, recovery of costs and capital expenditures as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen currently serves as the president of the Society of Utility Regulatory Financial Analysts.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages and Valuation
  - Utility valuation
  - Lost Profit

EXPERIENCE

Regulatory Finance

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- For several electric, gas and transmission utilities in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- She has estimated the cost of equity on behalf of Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.

- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their

acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.

- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 12 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.

Accounting and Corporate Finance

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.

- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.

- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.

- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.
- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

"*Risk and Return for Regulated Industries*," (with Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe) Elsevier, May 2017.

PUBLICATIONS AND REPORTS

"Using Electric and Gas Forwards to Manage Market Risks: When a power purchase agreement with a utility is not possible, standard forward contracts can act as viable hedging instruments," *North American Windpower*, May 2017, pp. 34-37.

"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

"Aurizon Network 2016 Access Undertaking: Aspects of the WACC," (with Mike Tolleth), filed with the *Queensland Competition Authority*, Australia, November 2016.

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

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"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

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"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Lessons from the U.S. and Australia" presented at *Seminar on the Cost of Capital in Regulated Industries: Time for a Fresh Perspective?* Brussels, October 2017.

"Should Regulated Utilities Hedge Fuel Cost and if so, How?" presented at *SURFA's 49 Financial Forum*, April 20-21, 2017.

"Transmission: The Interplay Between FERC Rate Setting at the Wholesale Level and Allocation to Retail Customers," (with Mariko Geronimo Aydin) presented at *Law Seminars International: Electric Utility Rate Cases*, March 16-17, 2017.

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2015-2017.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013-2017.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

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Direct, Rebuttal, Surrebuttal, Supplemental, Supplemental Rebuttal Testimony and Hearing Appearance on the Cost of Capital for Northern Illinois Gas Company submitted to the *Illinois Commerce Commission*, GRM #17-055, March, July, August, September, and November 2017.

Direct and Rebuttal Testimony on Cost of Capital for Portland General Electric Company submitted to the *Oregon Public Utility Commission* on behalf of Portland General Electric Company, Docket No. UE 319, February, July 2017.

Pre-filed Direct and Reply Testimony and Hearing Appearance on Cost of Equity and Capital Structure for Anchorage Municipal Light and Power, *Regulatory Commission of Alaska*, Docket No. TA357-121, December 2016, August and December 2017.

Expert report and Hearing Appearance regarding the Common Equity Ratio for OPG's Regulated Generation for OEB Staff, *Ontario Energy Board*, EB-2016-0152, November 2016, April 2017.

Pre-filed Direct Testimony on Cost of Equity and Capital Structure for Anchorage Municipal Wastewater Utility, *Regulatory Commission of Alaska*, Docket No. 158-126, November 2016.

Expert Report on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

Written evidence, rebuttal evidence and hearing appearance regarding the cost of equity and capital structure for Alberta-based utilities, the Alberta Utilities Commission, Proceeding No. 20622 on behalf of AltaGas Utilities Inc., ENMAX Power Corporation, FortisAlberta Inc., and The ATCO Utilities, February, May and June 2016.

Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2015.

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Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (*Confidential*)

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Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, EL11-13-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

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Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

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Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-08-0227, April 2008, February 2009, March 2009.

Expert Report, Supplemental Expert Report, and Hearing Appearance on the allocation of corporate overhead and damages from lost profit. *The International Centre for the Settlement of Investment Disputes*, Case No. ARB/03/29, February, April, and June 2008 (*Confidential*).

Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

CAPITAL ASSET PRICING MODEL

Table No. BV-ELEC-9

Risk Free Rate

[1]	Blue Chip 10-Year Forecast	3.40%
	US Government Bond Yields	
[2]	20-year	5.04%
[3]	10-Year	4.52%
[4]	Maturity Premium	0.52%
[5]	Blue Chip 10-Year Forecast Adjusted to 20-year Horizon	3.92%

Sources and Notes:

[1]: Blue Chip Economic Indicators, October 2017 U.S.

[2]-[3]: Supporting Schedule # 1 to Table No. BV-ELEC-9. Averages of monthly bond yields from December 1990 through November 2017.

[4]: [2] - [3].

[5]: [1] + [4].

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Regulated Subsample	Long-Term Risk-Free Rate [1]	ValueLine Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE		4.12%	0.75	6.94%	9.3%	9.7%
Alliant Energy	*	4.12%	0.70	6.94%	9.0%	9.4%
Amer. Elec. Power	*	4.12%	0.65	6.94%	8.6%	9.2%
Ameren Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
CenterPoint Energy		4.12%	0.90	6.94%	10.4%	10.5%
CMS Energy Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
Consol. Edison	*	4.12%	0.50	6.94%	7.6%	8.3%
DTE Energy						
Duke Energy	*	4.12%	0.60	6.94%	8.3%	8.9%
Edison Int'l	*	4.12%	0.65	6.94%	8.6%	9.2%
El Paso Electric	*	4.12%	0.80	6.94%	9.7%	10.0%
Entergy Corp.	*	4.12%	0.65	6.94%	8.6%	9.2%
IDACORP Inc.	*	4.12%	0.70	6.94%	9.0%	9.4%
MGE Energy		4.12%	0.75	6.94%	9.3%	9.7%
OGE Energy	*	4.12%	0.95	6.94%	10.7%	10.8%
Otter Tail Corp.	*	4.12%	0.90	6.94%	10.4%	10.5%
Pinnacle West Capital	*	4.12%	0.70	6.94%	9.0%	9.4%
PNM Resources						
Portland General	*	4.12%	0.70	6.94%	9.0%	9.4%
PPL Corp.	*	4.12%	0.70	6.94%	9.0%	9.4%
Public Serv. Enterprise		4.12%	0.70	6.94%	9.0%	9.4%
Xcel Energy Inc.	*	4.12%	0.60	6.94%	8.3%	8.9%
Average					9.0%	9.5%
Regulated Subsample Average					8.9%	9.4%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Bloomberg as of November 30, 2017.
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-10

Risk Positioning Cost of Equity of the U.S. Electric Sample

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Regulated Subsample	Long-Term Risk-Free Rate [1]	ValueLine Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE		3.92%	0.75	7.44%	9.5%	9.9%
Alliant Energy	*	3.92%	0.70	7.44%	9.1%	9.6%
Amer. Elec. Power	*	3.92%	0.65	7.44%	8.8%	9.3%
Ameren Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
CenterPoint Energy		3.92%	0.90	7.44%	10.6%	10.8%
CMS Energy Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
Consol. Edison	*	3.92%	0.50	7.44%	7.6%	8.4%
DTE Energy						
Duke Energy	*	3.92%	0.60	7.44%	8.4%	9.0%
Edison Int'l	*	3.92%	0.65	7.44%	8.8%	9.3%
El Paso Electric	*	3.92%	0.80	7.44%	9.9%	10.2%
Entergy Corp.	*	3.92%	0.65	7.44%	8.8%	9.3%
IDACORP Inc.	*	3.92%	0.70	7.44%	9.1%	9.6%
MGE Energy		3.92%	0.75	7.44%	9.5%	9.9%
OGE Energy	*	3.92%	0.95	7.44%	11.0%	11.1%
Otter Tail Corp.	*	3.92%	0.90	7.44%	10.6%	10.8%
Pinnacle West Capital	*	3.92%	0.70	7.44%	9.1%	9.6%
PNM Resources						
Portland General	*	3.92%	0.70	7.44%	9.1%	9.6%
PPL Corp.	*	3.92%	0.70	7.44%	9.1%	9.6%
Public Serv. Enterprise		3.92%	0.70	7.44%	9.1%	9.6%
Xcel Energy Inc.	*	3.92%	0.60	7.44%	8.4%	9.0%
Average					9.2%	9.6%
Regulated Subsample Average					9.1%	9.5%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Bloomberg as of November 30, 2017.
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Regulated Subsample	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	Utilities Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE		9.3%	9.7%	61.8%	-	0.0%	4.10%	38.2%	27.0%	6.9%	7.1%
Alliant Energy	*	9.0%	9.4%	59.9%	3.85%	1.8%	3.85%	38.3%	27.0%	6.5%	6.8%
Amer. Elec. Power	*	8.6%	9.2%	55.4%	-	0.0%	4.05%	44.6%	27.0%	6.1%	6.4%
Ameren Corp.	*	8.6%	9.2%	57.4%	-	0.0%	4.10%	42.6%	27.0%	6.2%	6.5%
CenterPoint Energy		10.4%	10.5%	51.0%	-	0.0%	3.85%	49.0%	27.0%	6.7%	6.7%
CMS Energy Corp.	*	8.6%	9.2%	48.5%	-	0.0%	4.10%	51.5%	27.0%	5.7%	6.0%
Consol. Edison	*	7.6%	8.3%	57.7%	-	0.0%	3.85%	42.3%	27.0%	5.6%	6.0%
DTE Energy											
Duke Energy	*	8.3%	8.9%	52.8%	-	0.0%	3.95%	47.2%	27.0%	5.7%	6.0%
Edison Int'l	*	8.6%	9.2%	55.4%	4.10%	5.7%	4.10%	38.9%	27.0%	6.2%	6.5%
El Paso Electric	*	9.7%	10.0%	56.1%	-	0.0%	4.10%	43.9%	27.0%	6.7%	6.9%
Entergy Corp.	*	8.6%	9.2%	48.0%	4.10%	1.0%	4.10%	51.0%	27.0%	5.7%	6.0%
IDACORP Inc.	*	9.0%	9.4%	62.2%	-	0.0%	4.10%	37.8%	27.0%	6.7%	7.0%
MGE Energy		9.3%	9.7%	77.0%	-	0.0%	3.72%	23.0%	27.0%	7.8%	8.1%
OGE Energy	*	10.7%	10.8%	68.1%	-	0.0%	3.85%	31.9%	27.0%	8.2%	8.2%
Otter Tail Corp.	*	10.4%	10.5%	66.5%	-	0.1%	4.10%	33.4%	27.0%	7.9%	8.0%
Pinnacle West Capital	*	9.0%	9.4%	62.8%	-	0.0%	3.90%	37.2%	27.0%	6.7%	7.0%
PNM Resources											
Portland General	*	9.0%	9.4%	54.3%	-	0.0%	4.10%	45.7%	27.0%	6.2%	6.5%
PPL Corp.	*	9.0%	9.4%	47.7%	-	0.0%	3.95%	52.3%	27.0%	5.8%	6.0%
Public Serv. Enterprise		9.0%	9.4%	65.0%	-	0.0%	4.10%	35.0%	27.0%	6.9%	7.2%
Xcel Energy Inc.	*	8.3%	8.9%	55.1%	-	0.0%	3.85%	44.9%	27.0%	5.8%	6.2%
Full Sample Average		9.0%	9.5%	58.1%	4.0%	0.4%	4.0%	41.4%	27.0%	6.5%	6.8%
Regulated Subsample Average		8.9%	9.4%	56.7%	4.0%	0.5%	4.0%	42.7%	27.0%	6.4%	6.6%

Sources and Notes:

[1]: Table No. BV-ELEC-10; Panel A, [4].
[2]: Table No. BV-ELEC-10; Panel A, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: Effective US/Oregon Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.

[9]-[10] A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points

Table No. BV-ELEC-11

Overall After-Tax Cost of Capital of the U.S. Electric Sample

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Regulated Subsample	CAPM Cost of Equity [1]	ECAPM (1.5%) Cost of Equity [2]	5-Year Average Common Equity to Market Value Ratio [3]	Weighted - Average Cost of Preferred Equity [4]	5-Year Average Preferred Equity to Market Value Ratio [5]	Weighted-Average Cost of Debt [6]	5-Year Average Debt to Market Value Ratio [7]	Utilities Representative Income Tax Rate [8]	Overall After-Tax Cost of Capital (CAPM) [9]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [10]
ALLETE		9.5%	9.9%	61.8%	-	0.0%	4.10%	38.2%	27.0%	7.0%	7.2%
Alliant Energy	*	9.1%	9.6%	59.9%	3.85%	1.8%	3.85%	38.3%	27.0%	6.6%	6.9%
Amer. Elec. Power	*	8.8%	9.3%	55.4%	-	0.0%	4.05%	44.6%	27.0%	6.2%	6.5%
Ameren Corp.	*	8.8%	9.3%	57.4%	-	0.0%	4.10%	42.6%	27.0%	6.3%	6.6%
CenterPoint Energy		10.6%	10.8%	51.0%	-	0.0%	3.85%	49.0%	27.0%	6.8%	6.9%
CMS Energy Corp.	*	8.8%	9.3%	48.5%	-	0.0%	4.10%	51.5%	27.0%	5.8%	6.0%
Consol. Edison	*	7.6%	8.4%	57.7%	-	0.0%	3.85%	42.3%	27.0%	5.6%	6.0%
DTE Energy											
Duke Energy	*	8.4%	9.0%	52.8%	-	0.0%	3.95%	47.2%	27.0%	5.8%	6.1%
Edison Int'l	*	8.8%	9.3%	55.4%	4.10%	5.7%	4.10%	38.9%	27.0%	6.2%	6.5%
El Paso Electric	*	9.9%	10.2%	56.1%	-	0.0%	4.10%	43.9%	27.0%	6.9%	7.0%
Entergy Corp.	*	8.8%	9.3%	48.0%	4.10%	1.0%	4.10%	51.0%	27.0%	5.8%	6.0%
IDACORP Inc.	*	9.1%	9.6%	62.2%	-	0.0%	4.10%	37.8%	27.0%	6.8%	7.1%
MGE Energy		9.5%	9.9%	77.0%	-	0.0%	3.72%	23.0%	27.0%	7.9%	8.2%
OGE Energy	*	11.0%	11.1%	68.1%	-	0.0%	3.85%	31.9%	27.0%	8.4%	8.4%
Otter Tail Corp.	*	10.6%	10.8%	66.5%	-	0.1%	4.10%	33.4%	27.0%	8.1%	8.2%
Pinnacle West Capital	*	9.1%	9.6%	62.8%	-	0.0%	3.90%	37.2%	27.0%	6.8%	7.1%
PNM Resources											
Portland General	*	9.1%	9.6%	54.3%	-	0.0%	4.10%	45.7%	27.0%	6.3%	6.6%
PPL Corp.	*	9.1%	9.6%	47.7%	-	0.0%	3.95%	52.3%	27.0%	5.9%	6.1%
Public Serv. Enterprise		9.1%	9.6%	65.0%	-	0.0%	4.10%	35.0%	27.0%	7.0%	7.3%
Xcel Energy Inc.	*	8.4%	9.0%	55.1%	-	0.0%	3.85%	44.9%	27.0%	5.9%	6.2%
Full Sample Average		9.2%	9.6%	58.1%	4.0%	0.4%	4.0%	41.4%	27.0%	6.6%	6.8%
Regulated Subsample Average		9.1%	9.5%	56.7%	4.0%	0.5%	4.0%	42.7%	27.0%	6.5%	6.7%

Sources and Notes:

[1]: Table No. BV-ELEC-10; Panel B, [4].
[2]: Table No. BV-ELEC-10; Panel B, [5].
[3]: Table No. BV-ELEC-4, [4].
[4]: Supporting Schedule #2 to Table No. BV-ELEC-11, Panel C.
[5]: Table No. BV-ELEC-4, [5].
[6]: Supporting Schedule #2 to Table No. BV-ELEC-11, P
[7]: Table No. BV-ELEC-4, [6].
[8]: Effective US/Oregon Corporate Tax Rate
[9]: ([1] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[10]: ([2] x [3]) + ([4] x [5]) + {[6] x [7] x (1 - [8])}.
[9]-[10] A strikethrough indicates the observation was excluded from the full sample average calculation as a result of its cost of equity estimate not exceeding its cost of debt by 150 basis points

Table No. BV-ELEC-12

Risk Positioning Cost of Equity at Representative Deemed Capital Structure

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	Utilities Representative Base Deemed % Debt	Representative Cost of BBB-Rated Utility Debt	Utilities Representative Income Tax Rate	Utilities Representative Base Deemed % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Full Sample:								
CAPM	6.5%	6.6%	50.0%	4.1%	27.0%	50.0%	10.0%	10.2%
ECAPM (1.50%)	6.8%	6.8%	50.0%	4.1%	27.0%	50.0%	10.5%	10.7%
Regulated Subsample:								
CAPM	6.4%	6.5%	50.0%	4.1%	27.0%	50.0%	9.7%	9.9%
ECAPM (1.50%)	6.6%	6.7%	50.0%	4.1%	27.0%	50.0%	10.2%	10.4%

Sources and Notes:

[1]: Table No. BV-ELEC-11; Panel A, [9] - [10].

[2]: Table No. BV-ELEC-11; Panel B, [9] - [10].

[3]: Utilities' Assumed Capital Structure.

[4]: Based on a BBB rating. Yield from Bloomberg as of November 30, 2017.

[5]: Effective US/Oregon Corporate Tax Rate.

[6]: Utilities' Assumed Capital Structure.

[7]: {[1] - ([3] x [4] x (1 - [5])}/ [6].

[8]: {[2] - ([3] x [4] x (1 - [5]))}/ [6].

Scenario 1: Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%.

Scenario 2: Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%.

Table No. BV-ELEC-13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company	Regulated Subsample	ValueLine Betas [1]	Debt Beta [2]	5-Year Average Common Equity to Market Value Ratio [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	5-Year Average Debt to Market Value Ratio [5]	Utilities Representative Income Tax Rate [6]	Asset Beta: Without Taxes [7]	Asset Beta: With Taxes [8]
ALLETE		0.75	0.10	61.8%	0.0%	38.2%	27.0%	0.50	0.55
Alliant Energy	*	0.70	0.05	59.9%	1.8%	38.3%	27.0%	0.44	0.48
Amer. Elec. Power	*	0.65	0.09	55.4%	0.0%	44.6%	27.0%	0.40	0.44
Ameren Corp.	*	0.65	0.10	57.4%	0.0%	42.6%	27.0%	0.42	0.46
CenterPoint Energy		0.90	0.05	51.0%	0.0%	49.0%	27.0%	0.48	0.55
CMS Energy Corp.	*	0.65	0.10	48.5%	0.0%	51.5%	27.0%	0.37	0.41
Consol. Edison	*	0.50	0.05	57.7%	0.0%	42.3%	27.0%	0.31	0.34
DTE Energy									
Duke Energy	*	0.60	0.07	52.8%	0.0%	47.2%	27.0%	0.35	0.39
Edison Int'l	*	0.65	0.10	55.4%	5.7%	38.9%	27.0%	0.40	0.44
El Paso Electric	*	0.80	0.10	56.1%	0.0%	43.9%	27.0%	0.49	0.55
Entergy Corp.	*	0.65	0.10	48.0%	1.0%	51.0%	27.0%	0.36	0.41
IDACORP Inc.	*	0.70	0.10	62.2%	0.0%	37.8%	27.0%	0.47	0.52
MGE Energy		0.75	0.05	77.0%	0.0%	23.0%	27.0%	0.59	0.62
OGE Energy	*	0.95	0.05	68.1%	0.0%	31.9%	27.0%	0.66	0.72
Otter Tail Corp.	*	0.90	0.10	66.5%	0.1%	33.4%	27.0%	0.63	0.68
Pinnacle West Capital	*	0.70	0.06	62.8%	0.0%	37.2%	27.0%	0.46	0.51
PNM Resources									
Portland General	*	0.70	0.10	54.3%	0.0%	45.7%	27.0%	0.43	0.47
PPL Corp.	*	0.70	0.10	47.7%	0.0%	52.3%	27.0%	0.39	0.43
Public Serv. Enterprise		0.70	0.07	65.0%	0.0%	35.0%	27.0%	0.48	0.52
Xcel Energy Inc.	*	0.60	0.10	55.1%	0.0%	44.9%	27.0%	0.38	0.41
Full Sample Average		0.71	0.08	58.1%	0.4%	41.4%	27.0%	0.45	0.50
Regulated Subsample Average		0.69	0.09	56.7%	0.5%	42.7%	27.0%	0.43	0.48

Sources and Notes:

[1]: Supporting Schedule # 1 to Table No. BV-ELEC-10, [1].
[2]: Supporting Schedule #1 to Table No. BV-ELEC-13, [7].
[3]: Table No. BV-ELEC-4, [4].
[4]: Table No. BV-ELEC-4, [5].
[5]: Table No. BV-ELEC-4, [6].
[6]: Effective US/Oregon Corporate Tax Rate
[7]: [1]*[3] + [2]*([4] + [5]).
[8]: {[1]*[3] + [2]*([4]+[5]*(1-[6]))} / {[3] + [4] + [5]*(1 -[6])}.

Table No. BV-ELEC-14

Sample Average Asset Beta Relevered at Representative Deemed Capital Structure

	Asset Beta [1]	Assumed Debt Beta [2]	Utilities Representative Base Deemed % Debt [3]	Utilities Representative Income Tax Rate [4]	Utilities Representative Base Deemed % Equity [5]	Estimated Equity Beta [6]
Full Sample:						
Asset Beta Without Taxes	0.45	0.05	50.0%	27.0%	50.0%	0.85
Asset Beta With Taxes	0.50	0.05	50.0%	27.0%	50.0%	0.82
Regulated Subsample:						
Asset Beta Without Taxes	0.43	0.05	50.0%	27.0%	50.0%	0.82
Asset Beta With Taxes	0.48	0.05	50.0%	27.0%	50.0%	0.79

Sources and Notes:

[1]: Table No. BV-ELEC-13, [7] - [8].

[2]: Debt Beta estimate for BBB rated entities. Corporate Finance, Berk and Demarzo, Second Edition, p. 389.

[3]: Utilities' Assumed Capital Structure.

[4]: Effective US/Oregon Corporate Tax Rate.

[5]: Utilities' Assumed Capital Structure.

[6]: [1] + [3]/[5]*([1] - [2]) without taxes, [1] + [3]*(1 - [4])/[5]*([1] - [2]) with taxes.

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.12%, Long-Term Market Risk Premium of 6.94%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:					
Asset Beta Without Taxes	4.12%	0.85	6.94%	10.0%	10.2%
Asset Beta With Taxes	4.12%	0.82	6.94%	9.8%	10.1%
Regulated Subsample:					
Asset Beta Without Taxes	4.12%	0.82	6.94%	9.8%	10.1%
Asset Beta With Taxes	4.12%	0.79	6.94%	9.6%	9.9%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. BV-ELEC-15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.92%, Long-Term Market Risk Premium of 7.44%

Company	Long-Term Risk-Free Rate [1]	Hamada Adjusted Equity Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
Full Sample:					
Asset Beta Without Taxes	3.92%	0.85	7.44%	10.3%	10.5%
Asset Beta With Taxes	3.92%	0.82	7.44%	10.0%	10.3%
Regulated Subsample:					
Asset Beta Without Taxes	3.92%	0.82	7.44%	10.0%	10.3%
Asset Beta With Taxes	3.92%	0.79	7.44%	9.8%	10.1%

Sources and Notes:
[1]: Villadsen Direct Evidence.
[2]: Table No. BV-ELEC-14, [6].
[3]: Villadsen Direct Evidence.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

UE 335 / PGE / 1100
Riter – Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Amber Riter
Alison Lucas

February 15, 2018

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Amber M. Riter. I am an Economist and the Principle Load Forecasting Analyst at PGE.

My name is Alison Lucas. I am a Senior Load Forecasting Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents PGE's 2019 test year energy and customer forecast.[1]

Q. What load forecast related request does PGE make of the Public Utility Commission of Oregon (Commission) in this proceeding?

A. We request the Commission: 1) accept PGE's methodology including modeling changes described in this testimony and the use of a trended weather normal assumption; 2) accept, as a preliminary matter, our forecast of energy deliveries recognizing that updates will be made throughout the course of this proceeding, and 3) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2019.

Q. Does PGE intend to update its 2019 forecast during this case?

A. Yes, we intend to update the test-year forecast as we have in prior cases. Updates will include model re-estimation to: 1) incorporate more current load and economic data as they become available; 2) refresh the forward-looking inputs, including the economic outlook for Oregon; and 3) incorporate the most current operational information in large customers' usage forecasts.

[1] We use the terms "energy deliveries" and "load forecast" interchangeably in this testimony.

Q. Please describe PGE's delivery forecast.

A. PGE's 2019 test year energy forecast is for energy deliveries of 19,041 thousand megawatt-hours (MWh), on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE cost-of-service rates for direct access under Schedules 485 and 489. The forecast reflects current expected economic conditions for Oregon in 2019, as well as operational changes among PGE's largest customers and savings from incremental energy efficiency (EE) programs that are implemented by the Energy Trust of Oregon (ETO).

Q. How does the 2019 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2019 forecast reflects stronger growth in deliveries to industrial (primary voltage service) customers relative to lower growth anticipated in the residential and commercial customer classes. Industrial deliveries growth is related to high-tech expansion and new data centers. Although higher than in other customer classes, the rate of growth in deliveries to industrial customers has slowed as initial phases in a large high-tech construction project are completed.

Table 1 below summarizes the MWh delivery forecast in annual percentage changes by voltage service customer class on a weather adjusted, billing cycle basis from 2015 through 2019.

Table 1

Percent Change in MWh Delivery from Preceding Year: 2015-2019

Voltage Service Class	2015	2016	2017	2018 (E)	2019 (E)
Residential	-0.7%	0.5%	-1.4%	0.2%	-0.1%
General Service[2]	0.1%	-1.4%	0.6%	-0.8%	-1.4%
Transmission	4.2%	-56.2%	-2.7%	-38.9%	0.0%
Primary	7.0%	1.5%	3.8%	1.4%	1.7%
Total	1.2%	-2.6%	0.4%	-0.7%	-0.2%

[2] General Service is the summation of Secondary Voltage and Miscellaneous Schedules.

Q. How has PGE's load forecast performed compared to industry standard?

A. While forecasts are always subject to uncertainty, PGE's load forecast has performed very well over the years. Table 2 displays PGE's load forecast variance, compared to industry averages, measured in mean absolute percentage error (MAPE), as reported in Itron's annual load forecasting benchmark survey.

Table 2

Comparison of PGE Forecast Error to Itron Benchmark Survey

	2011		2012		2013		2014		2015		2016	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	-0.5%	1.5%	0.0%	1.7%	0.3%	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%
Commercial	1.7%	-0.4%	2.0%	-1.4%	2.1%	-1.9%	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%
Industrial	3.2%	-0.7%	3.2%	-4.5%	4.4%	-8.8%	3.4%	-0.5%	3.0%	2.8%	3.3%	-2.7%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%

II. Forecast Methodology and Process

Q. Please summarize the process you use to develop the retail energy deliveries forecast.

A. We use monthly time-series regression models to estimate the residential, commercial and manufacturing sectors, based on the relationship between energy deliveries and weather variables, economic variables, and seasonal control variables. The most current forecasted explanatory variables are applied to the coefficients from the regression models to develop the energy deliveries forecast.

Q. How do you group customers in your forecast models?

A. We forecast demand (MWh delivery) for residential, commercial, manufacturing customers and energy served under miscellaneous rate schedules (See Exhibit 1101). For residential customers, we model both customer counts and usage per customer for seven segments based on dwelling type and space heating type. We group commercial and manufacturing customers into eleven commercial and seven manufacturing groups according to the North American Industrial Classification System (NAICS) definition of business segments.[3] Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government, and financial institutions. Manufacturing customers include producers of paper, lumber, steel, machinery, micro-processors, solar panels, and transportation equipment.

Q. How do you forecast the gross loads delivered to the PGE system?

A. This process involves three steps: 1) aggregated cycle-based NAICS sector MWh deliveries are converted into voltage service levels using ratios based on historical data; 2) cycle-based energy deliveries are converted to calendar-based deliveries using cycle-to-calendar ratios;

[3] https://www.census.gov/eos/www/naics/.

and 3) transmission and distribution (line) losses are added to deliveries at the meter to obtain the bus bar energy (MWh or MWa) required to meet the aggregated end users' demand. For the 2019 test year, we apply line loss factors as established in PGE's 2015 general rate case (Docket No. UE 283).

Q. Are these models new or different from previous PGE energy delivery models?

A. The forecast models and process remain fundamentally the same as those used in previous filings with the Commission. However, there are some updates in model specifications, specifically with respect to reexamination of the underlying structure of historical data series and relationships to weather and economic drivers.

Q. What changes have been made to model specifications?

A. In Docket No. UE 319, PGE agreed to conduct further analysis of non-stationarity in its load forecast regression models. PGE tested for deterministic trends and breakpoints and found that most of the sector energy deliveries time series do not show evidence of a unit root after accounting for those trends and breakpoints. Instead, most series are stationary or trend stationary. As a result of this analysis, trend variables and breakpoints are included in the regression equations where appropriate. Additionally, PGE has maintained "flat" forecasts for any series that showed evidence of unit root non-stationarity. PGE's Load Forecast work papers contain the testing results that support choice of model structure for each of PGE's regression models.

Q. Have any other changes been made to PGE's documentation of its forecasting process?

A. Yes, PGE has documented a series of testing procedures for each of its regression-based forecasts as evidence to support choice of model structure and variables. These tests include: univariate analysis of each series to understand the underlying structure of the series, including trends, breaks, and outliers; scatter plots of each energy deliveries variable to temperature to inform the choice of weather variables, specifically related to the set points used for heating and cooling degree days; and out-of-sample testing comparing updated model specifications to prior forecast model run. Furthermore, PGE has revised its supplemental process work papers with the focus of providing clear and useful documentation of its forecasting process.

Q. Did you make any adjustments for incremental EE to the forecast?

A. Yes. We adjusted the forecast to account for the impact of PGE's incremental EE programs funded through Schedule 109 Incremental EE Funding, enabled by Senate Bill 838 (SB 838), as forecasted by the ETO, and updated in November of 2017. Since EE trends, including SB 1149[4] measures, are assumed to be captured implicitly in the forecast model, no explicit adjustments are made for SB 1149 savings. The incremental EE program levels reflect the increased funding for EE programs under SB 838, starting in November 2017, the first month of the forecast.

Q. Has PGE made any changes to its EE adjustment since UE 319?

A. No, PGE has not changed its approach to the EE adjustment. In UE 319, Commission Staff recommended an alternative approach citing concern with the incremental versus embedded nature of SB 838 savings. PGE recognizes that as time passes since the issuance of SB 838 in 2007, the level of embedded savings becomes less clear. While PGE is interested in investigating alternative approaches, at this time we believe our current adjustment mechanism performs well and is both appropriate and necessary for the development of PGE's energy deliveries forecast.

[4] Oregon Senate Bill 1149 established the 3% public purpose charge to fund and encourage energy conservation.

Q. What is the impact of incremental EE programs savings on the forecast?

A. We estimate a total of 300.6 thousand MWh or 1.6% savings from these programs in the 2019 test year based on the EE savings starting in November 2017 and accumulating through December 2019. PGE Exhibit 1102 shows the forecast adjusted for incremental EE savings and PGE Exhibit 1103 shows the savings from the incremental EE programs that are included in PGE's delivery forecast.

III. Input Assumptions

Q. What sources of information do you use to forecast energy deliveries?

A. PGE relies on the Oregon Department of Administrative Services' Office of Economic Analysis (OEA) for the Oregon economic forecast. OEA's December 2017 employment forecasts were used to develop the forecast for this proceeding. In addition, customers who are large energy users provide us with specific operational information, direct inputs and, if available, forecasts of energy use through correspondence with PGE's Business Customer Group. PGE's Corporate Finance Group performs credit-risk analysis for these large customers, providing additional credit-risk and financial performance information on our large customers.

Q. How current are the data you use to estimate the model?

A. The models estimated for use in this proceeding are based on energy data through the October 2017 billing cycle and customer connects data through August 2017.

Q. What assumption did you make regarding weather variables in the forecast?

A. The test-year forecast is based on a trended normal weather assumption to capture gradual warming observed in the Portland area over the last 40 years. The normal weather series is estimated using monthly degree day data from 1941 to 2016, with a simple average from 1941 to 1975 and a linear trend fit to data from 1976 to 2016.

Q. Is the assumption regarding weather variables used in the forecast different from that used in prior PGE forecasts?

A. Yes. Since Docket No. UE 180, PGE has used a 15-year moving average to represent normal weather conditions. PGE first proposed use of the trended weather assumption in UE 319 and described the approach in detail in its direct testimony for the case. While

OPUC Staff stated interest in a more sophisticated approach to the 15-year average weather input assumption,[5] Parties stipulated that PGE should use 15-year average weather in the final forecast as adopted by Order No. 17-511.

Q. Why is PGE proposing the trended weather forecast assumption again?

A. PGE strives for an expected mid-point load forecast; that is, a "50/50" load forecast where there is a 50% chance that the actual outcome falls short of or exceeds the forecast. To achieve this, forecast assumptions must also be based on an expected mid-point, where it is equally likely that the outcome falls short of or exceeds the assumption. In the case of a persistent warming trend, as experienced in the Pacific Northwest, a moving average approach contains a cold bias[6] and does not achieve a 50/50 forecast. PGE proposes the trended weather approach to better approximate a 50/50 forecast for expected weather.

Q. What are the primary impacts of this weather assumption on PGE's load forecast results?

A. Using the trended weather assumption decreases PGE's annual energy deliveries forecast by approximately 49.1 thousand MWh's, or 0.3%, in 2019 compared to the use of a 15-year normal weather assumption. Within this total change is a seasonal shift in PGE's energy deliveries, primarily in the residential customer forecast, decreasing deliveries in the heating months, and increasing deliveries in the cooling season.

Q. How does the change in weather assumption impact PGE's Decoupling Mechanism?

A. PGE Exhibit 1200 outlines a decoupling mechanism that is based on actual (rather than weather adjusted) energy deliveries. In the context of this updated approach, the weather

[5] See UE 319 Staff/700 Kaufman.
[6] A cold bias in the weather assumptions means that we systematically underestimate average temperature.

adjustment itself is not relevant to the calculation of the decoupling adjustment. Use of an unbiased assumption to describe normal weather, theoretically, reduces price volatility that might be created given an embedded bias towards cooler weather.

Q. Has a similar trended weather approach been used in other utility electric load forecasts?

A. While other utilities have proposed a similar approach, PGE is not aware of any other regulated utility using a trended weather assumption in its energy deliveries forecast for rate making proceedings. However, the Energy Information Administration's Annual Energy Outlook uses trended weather assumptions that reflect regional warming.[7] PGE recognizes that this is an innovative approach and believes capturing a warming trend is appropriate in the context of the energy deliveries forecast, particularly in the long term.

[7] https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf , p31.
https://www.eia.gov/outlooks/aeo/assumptions/pdf/commercial.pdf , p43.

IV. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. For the 2019 test year, we forecast deliveries of 7,506 thousand MWh to 781,152 residential customers. Declines in residential use per customer, driven by incremental EE programs, are offset by customer growth of 1.3% in 2019 for annual residential energy deliveries decrease of -0.1% over 2018. The residential forecast includes residential outdoor area lighting energy. PGE Exhibit 1104 shows the forecast of building permits, new connects, and customer counts. PGE Exhibit 1105 displays the forecast of kWh use per customer and deliveries to residential customers in detail.

Q. What are the key results of PGE's commercial sector forecast?

A. For the 2019 test year, we forecast deliveries of 6,800 thousand MWh to NAICS-based commercial customers, a 1.5% decrease over forecasted 2018 energy deliveries of 6,903 thousand MWh. Declining energy deliveries to the commercial NAICS groups reflect savings from incremental EE programs larger than those projected in the residential sector, impacting the NAICS-based commercial sector by -2.6% for 2019. PGE's Exhibit 1106 contains the detailed forecast of deliveries to commercial consumers.

Q. What are the key results of PGE's manufacturing sector forecast?

A. For the test year 2019, we forecast deliveries of 4,605 thousand MWh to NAICS-based manufacturing customers, 1.5% higher than forecasted 2018 deliveries, following growth of 4.2% in 2017 and a decline of 2.3% in 2018. The manufacturing forecast reflects continued expansion by high-tech and related companies in our service territory. Manufacturing sector deliveries can show large swings from year to year due to specific individual company operations and industry conditions. For example, the closure of two large paper customers, one at the end of 2015 and one at the end of 2017, significantly impacted PGE's energy deliveries growth rates. PGE Exhibit 1107 presents the detailed delivery forecast of the manufacturing sector.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries to miscellaneous rate schedules account for approximately 1% of total retail deliveries in 2018. PGE Exhibit 1108 displays the miscellaneous schedules' forecast

Q. Did you make a separate forecast of delivery to Rate Schedule 485/489 customers?

A. Yes. PGE separates the delivery of energy to customers who chose service under Schedule 485/489 (direct access) by 2017 year-end from the energy delivery forecast to customers served under PGE cost-of-service (COS) rates, including variable-price (market power) customers. Schedule 485/489 is the only service under which we forecast customers to receive direct access service in 2019. We prorate the COS and Schedule 485/489 deliveries by applying these customers' respective historical shares of service level or revenue class energy to the forecast. PGE Exhibit 1110 shows the forecast of deliveries in 2019 to PGE COS customers and direct access (Schedule 485/489) customers.

V. Forecast Uncertainty

Q. Is the forecast subject to uncertainty?

A. Yes. The MWh delivery forecast we submit in this filing is our "expected" or mid-point estimate, but is subject to uncertainty. As such, it is a 50/50 "point" forecast, a 50% chance that the actual outcome falls short of or exceeds the forecast. As with any forecast, actual conditions may differ from what we assumed or anticipated in the forecast, resulting in a different outcome.

As mentioned with respect to the proposed trended weather approach, the accuracy of a forecast depends not only on the model specification, but also on the accuracy of the independent variables driving the forecast. In our model, the independent variables include weather variables and the economic forecast drivers. In addition, the model includes assumptions surrounding implementation of EE programs, key customers' operational decisions, new customers' entry or existing customers' exit, and the absence of unforeseen natural disasters, wars or geopolitical turmoil. The accuracy of our forecast will be impacted by the extent to which actual outcomes of these variables differ from our assumptions.

Q. How do you address uncertainty in your forecast?

A. PGE aims to reduce uncertainty by using the most current information available in its forecast models. PGE's input assumptions, such as employment forecasts, weather data, and actual load, are refreshed in each forecast. PGE tracks forecast performance on a monthly basis and updates its forecast multiple times in any given year to include the most recent historical trends, billing data, and input assumptions available. We expect to include a June update and a September update as the final forecast for setting 2019 rates.

VI. Qualifications

Q. Ms. Riter, please describe your qualifications.

A. I received my Bachelor of Arts in Economics from New Mexico State University and my Master of Arts in Economics from The University of New Mexico. I have been working as an Economist in energy deliveries forecasting for the past 8 years. Prior to joining PGE in 2014, I worked at PNM Resources, the parent company of Public Service Company of New Mexico (PNM) and Texas New Mexico Power (TNMP), performing load forecasting and load research analysis.

Q. Ms. Lucas, please describe your qualifications.

A. I received my Bachelor of Arts in Physics from Colgate University. I have been working as a data analyst in various capacities for the past 11 years. Prior to joining PGE in 2016, I worked at DNV GL using high resolution meteorological and wind turbine performance data to forecast wind farm energy production. Prior to that, I worked for IBM as a management consultant to federal agencies.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1101	Energy Deliveries Forecast by Market Segment and Service Level
1102	Energy Deliveries Forecast after EE adjustments
1103	Forecast of Incremental Energy Efficiency Savings
1104	Residential Building Permits, New Connects, Vacancy Rates and Customer Count History
1105	Forecast of Residential Use per Customer
1106	Commercial Energy Deliveries Forecast
1107	Manufacturing Deliveries Forecast by NAICS Sector
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Energy Deliveries Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast [1]

	(in thousand MWh)					% Change [2]				
	2015	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Schedule 7	7,563	7,600	7,495	7,547	7,587	-0.7%	0.5%	-1.4%	0.7%	0.5%
Residential Lighting	3	3	3	3	3	-33.6%	-2.2%	-0.8%	-0.5%	0.0%
Total Residential	7,567	7,604	7,498	7,550	7,591	-0.7%	0.5%	-1.4%	0.7%	0.5%
Commercial [3]	6,988	6,920	6,913	6,975	6,979	0.0%	-1.0%	-0.1%	0.9%	0.1%
Manufacturing [3]	4,907	4,458	4,649	4,555	4,643	6.0%	-9.1%	4.3%	-2.0%	1.9%
Miscellaneous Customers	190	166	156	155	155	-1.4%	-12.8%	-6.1%	0.0%	-0.4%
Secondary Voltage	7,320	7,239	7,291	7,313	7,322	0.1%	-1.1%	0.7%	0.3%	0.1%
Total General Service	7,510	7,405	7,447	7,468	7,477	0.1%	-1.4%	0.6%	0.3%	0.1%
Primary Voltage Service	3,700	3,756	3,898	3,964	4,047	7.0%	1.5%	3.8%	1.7%	2.1%
Transmission Voltage Service	874	382	372	227	227	4.2%	-56.2%	-2.7%	-38.9%	0.0%
Total Retail [4]	19,651	19,147	19,215	19,209	19,341	1.2%	-2.6%	0.4%	0.0%	0.7%

1 SDEC17B_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Energy Deliveries Forecast (Energy Efficiency Adjusted) by Market Segment and Service Level

(at average weather)

Net of Incremental Energy Efficiency [1]

	(in thousand MWh)					% Change [2]				
	2015	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Schedule 7	7,563	7,600	7,495	7,507	7,503	-0.7%	0.5%	-1.4%	0.2%	-0.1%
Residential Lighting	3	3	3	3	3	-33.6%	-2.2%	-0.8%	-0.5%	0.0%
Total Residential	7,567	7,604	7,498	7,510	7,506	-0.7%	0.5%	-1.4%	0.2%	-0.1%
Commercial [3]	6,988	6,920	6,913	6,903	6,800	0.0%	-1.0%	-0.1%	-0.1%	-1.5%
Manufacturing [3]	4,907	4,458	4,649	4,539	4,605	6.0%	-9.1%	4.3%	-2.4%	1.5%
Miscellaneous Customers	190	166	156	155	155	-1.4%	-12.8%	-6.1%	0.0%	-0.4%
Secondary Voltage	7,320	7,239	7,291	7,235	7,132	0.1%	-1.1%	0.7%	-0.8%	-1.4%
Total General Service	7,510	7,405	7,447	7,391	7,287	0.1%	-1.4%	0.6%	-0.8%	-1.4%
Primary Voltage Service	3,700	3,756	3,898	3,953	4,021	7.0%	1.5%	3.8%	1.4%	1.7%
Transmission Voltage Service	874	382	372	227	227	4.2%	-56.2%	-2.7%	-38.9%	0.0%
Total Retail [4]	19,651	19,147	19,215	19,081	19,040	1.2%	-2.6%	0.4%	-0.7%	-0.2%

1 SDEC16E_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2018	2019
Base (B) Forecast	19,209	19,341
Incremental EE Savings [1]	(128)	(301)
Post-EE Forecast (E) [2]	19,081	19,040

1 Energy Trust of Oregon (ETO) annual savings deployment forecast.

2 Totals and differences may not foot due to rounding.

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2015	2016	2017 [1, 2]	2018 [2]	2019 [2]
Building Permits [3]					
Single-Family	9,999	10,629	10,472	10,931	11,531
Multi-Family	6,371	8,082	8,129	9,329	9,828
New Connects					
Single-Family	4,480	5,410	4,730	5,610	5,922
Multi-Family	3,965	4,713	5,392	5,590	4,939
Mobile Home	64	111	97	60	60
Other	41	32	11	24	24
Total Residential Connects	8,550	10,266	10,230	11,284	10,945
Commercial Connects	1,935	1,858	2,252	2,419	2,407
Total New Connects	10,485	12,124	12,482	13,703	13,352
Residential Customer Counts					
Single-Family Heat	109,572	110,374	110,910	111,209	111,565
Single-Family Non-Heat	354,075	358,731	363,094	366,992	371,496
Multiple-Family Heat	180,880	184,326	187,825	191,495	195,045
Multiple-Family Non-Heat	58,743	59,641	60,972	62,489	64,018
Mobile Home Heat	30,417	30,501	30,609	30,517	30,328
Mobile Home Non-Heat	3,908	3,932	3,935	3,915	3,897
Other	4,872	4,883	4,866	4,831	4,802
Total Number of Accounts [4]	742,467	752,388	762,211	771,448	781,152

1 Includes actuals through December 2017, except for connects which include actuals through November 2017 and forecast for December 2017

2 Forecasted values are identical for base and energy efficiency forecast

3 Oregon building permits

4 Includes vacant accounts

Forecast of Residential Use per Customer and Ultimate Deliveries

(at average weather)

Net of Incremental Energy Efficiency [1]

	2015 [2]	2016 [2]	2017 [2]	2018	2019
Use per Customer (kWh)					
Single-Family Heat	14,808	14,813	14,378	13,971	13,721
Single-Family Non-Heat	10,112	10,010	9,849	9,890	9,820
Multiple-Family Heat	8,220	8,090	7,740	7,636	7,512
Multiple-Family Non-Heat	6,004	5,959	5,875	5,912	5,880
Mobile Home Heat	14,028	14,167	13,694	13,171	12,979
Mobile Home Non-Heat	10,722	10,914	10,525	10,358	10,287
Other	10,703	10,827	10,536	10,207	10,092
Average Use per Customer	10,187	10,102	9,833	9,731	9,604
Ultimate Deliveries (millions of kWh)					
Single-Family Heat	1,623	1,635	1,595	1,554	1,531
Single-Family Non-Heat	3,580	3,591	3,576	3,630	3,648
Multiple-Family Heat	1,487	1,491	1,454	1,462	1,465
Multiple-Family Non-Heat	353	355	358	369	376
Mobile Home Heat	427	432	419	402	394
Mobile Home Non-Heat	42	43	41	41	40
Other	52	53	51	49	48
Schedule 6 & 7 Deliveries	7,563	7,600	7,495	7,507	7,503
Residential Lighting	3	3	3	3	3
Total Residential Deliveries	7,567	7,604	7,498	7,510	7,506

1 SDEC17E_W75

2 Weather-adjusted

Commercial Energy Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

						% Change [1]				
	2015 [2]	2016 [2]	2017 [2]	2018	2019	2015	2016	2017	2018	2019
Food Stores	456	431	421	412	398	-2.0%	-5.5%	-2.3%	-2.1%	-3.5%
Govt. & Education	998	969	984	971	957	0.3%	-3.0%	1.6%	-1.4%	-1.4%
Health Services	729	721	718	731	727	-0.3%	-1.2%	-0.3%	1.7%	-0.5%
Lodging	105	107	106	103	102	0.9%	1.5%	-0.7%	-2.6%	-1.8%
Misc. Commercial	640	665	712	705	699	0.1%	4.0%	7.0%	-0.9%	-0.8%
Department Stores/Malls	350	343	332	338	334	-0.3%	-2.1%	-3.0%	1.7%	-1.1%
Office & F.I.R.E. [3]	1018	993	954	963	945	-3.1%	-2.5%	-3.9%	0.9%	-1.9%
Other Services	834	863	867	864	855	3.8%	3.5%	0.5%	-0.4%	-1.0%
Other Trade	727	720	713	710	692	0.5%	-1.0%	-0.9%	-0.4%	-2.6%
Restaurants	481	480	481	487	486	0.5%	-0.2%	0.1%	1.4%	-0.3%
Trans., Comm. & Utility	649	629	629	619	606	-0.5%	-3.1%	0.0%	-1.6%	-2.1%
Total Commercial	6,988	6,920	6,918	6,903	6,800	-0.1%	-1.0%	0.0%	-0.2%	-1.5%

1 Calculated using rounded-numbers

2 Weather-adjusted

3 Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2015 [2]	2016 [2]	2017 [2]	2018	2019	2015	2016	2017	2018	2019
Food & Kindred Products	247	257	268	269	269	4.8%	3.9%	4.3%	0.1%	0.1%
High Tech	2,368	2,459	2,588	2,650	2,732	10.6%	3.8%	5.2%	2.4%	3.1%
Lumber & Wood	95	93	101	97	96	-2.8%	-2.9%	8.5%	-4.0%	-0.7%
Metal Manufacturing and Fab	478	450	445	439	436	-2.9%	-5.9%	-1.1%	-1.5%	-0.6%
Other Manufacturing	737	712	767	748	736	-1.7%	-3.4%	7.7%	-2.5%	-1.6%
Paper & Allied Products	788	313	297	158	158	10.7%	-60.2%	-5.1%	-46.8%	-0.1%
Transportation Equipment	191	173	178	179	178	3.5%	-9.6%	2.9%	0.4%	-0.2%
Total Manufacturing	4,907	4,458	4,644	4,539	4,605	6.3%	-9.1%	4.2%	-2.3%	1.5%

1 Calculated using rounded-numbers

2 Weather-adjusted

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2015	2016	2017	2018 [2]	2019 [2]	2015	2016	2017	2017	2018
Residential										
Outdoor Area Lighting (15R) [3]	3	3	3	3	3	-33.6%	-2.2%	-0.8%	-0.5%	0.0%
Secondary (Commercial)										
Outdoor Area Lighting (15C) [4]	13	13	13	13	12	-9.0%	-1.8%	-2.0%	-2.4%	-1.9%
Farm Irrigation et al. [5]	92	80	79	85	86	15.6%	-13.4%	-0.7%	7.7%	1.3%
Street and Other Lighting [6]	84	73	63	58	56	-14.2%	-13.9%	-12.7%	-9.2%	-2.7%
Total Miscellaneous Commercial	190	166	156	155	155	-1.4%	-12.8%	-6.1%	0.0%	-0.4%
All Miscellaneous Schedules [7]	193	169	159	159	158	-2.3%	-12.6%	-6.0%	0.0%	-0.4%

1 Calculated from rounded numbers

2 Identical for non-price, price-effect and post-EE forecasts

3 Existing Schedule 15R

4 Existing Schedule 15C

5 Existing Schedules 47 & 49

6 Existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

7 Equals line 2 + line 7

Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency [4]

	Million kWh [1]	Average MW [2]	Peak MW [3]
2010	18,893	2,274	3,582
2011	19,138	2,334	3,555
2012	19,248	2,312	3,597
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,651	2,344	3,914
2016	19,147	2,287	3,726
2017	19,215	2,389	3,976
2018	19,081	2,318	3,613
2019	19,040	2,313	3,610

1 Cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through 2017

2 Calendar basis, at the bus bar, actual through 2017, not adjusted for weather.

3 Coincidental annual system peak at bus bar; includes actual through 2017, not adjusted for weather.

4 2018 and 2019 are the incremental EE adjusted forecast.

Forecast of 2019 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service [1]	Direct Access [2]	Total Delivery [3]
Residential	7,506	0	7,506
Secondary	6,652	579	7,231
Primary	2,816	1,205	4,021
Transmission	58	169	227
Lighting	56	0	56
Total Retail [3]	17,088	1,953	19,041

1 Includes economic replacement VPO deliveries

2 Schedule 485/489 deliveries

3 Totals may not add due to rounding.

Trended Weather HDD and CDD Comparison

2019 Weather Variables

Billing Month	Based on Trended Approach HDD65	Based on Trended Approach CDD65	Based on 15-Year Avg. (2002-2016) HDD65	Based on 15-Year Avg. (2002-2016) CDD65
January	753.5	0.0	775.4	0.0
February	639.0	0.0	664.5	0.0
March	557.8	0.0	573.6	0.0
April	409.7	0.2	438.1	0.5
May	272.7	7.3	297.3	7.1
June	137.3	36.2	153.8	31.8
July	46.8	115.5	43.7	108.2
August	11.7	195.7	4.3	178.3
September	22.6	173.9	19.3	149.1
October	103.3	44.1	122.0	36.9
November	322.8	1.4	342.4	1.9
December	642.1	0.0	660.4	0.0
Annual	3,919.4	574.3	4,094.8	513.9

Trended Weather Approach Resources

Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." Journal of Applied Meteorology and Climatology, vol. 46, 2007, pp. 1759-1776, http://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1. Accessed Nov. 2016.

Livezey, Robert E. and Philip Q Hanser. "Redefining Normal Temperatures: Resource planning and forecasting in a changing climate." Fortnightly Magazine, May 2013, https://www.fortnightly.com/fortnightly/2013/05/redefining-normal-temperatures. Accessed Nov. 2016.

Wilks, Daniel S. and Robert E. Livezey. "Performance of Alternative "Normals" for Tracking Climate Changes, Using Homogenized and Nonhomogenized Seasonal U.S. Surface Temperatures." Journal of Applied Meteorology and Climatology, vol. 52, 2013, pp. 1677-1687, http://journals.ametsoc.org/doi/pdf/10.1175/JAMC-D-13-026.1. Accessed Nov. 2016.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Robert Macfarlane
Jacob Goodspeed

February 15, 2018

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am Interim Manager, Pricing and Tariffs for Portland General Electric Company (PGE). I am responsible, along with Mr. Goodspeed, for the development of the marginal cost studies.

My name is Jacob Goodspeed. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE. I am also responsible for the development of the marginal cost studies.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony describes the methodologies and results of PGE's generation, transmission, distribution, customer service, and street lighting marginal cost of service studies. PGE Exhibit 1201 provides a summary of these marginal costs by component. The summary lists costs by PGE rate schedule for generation capacity and energy, transmission, subtransmission, substation, feeder backbone and tapline, transformers, service laterals, meters, and customer service costs. Rate schedule changes are discussed in PGE Exhibit 1301.

Q. What is the purpose of the distribution and customer marginal cost studies?

A. The purpose is to calculate the incremental or marginal unit cost of service for various categories (e.g., distribution substations, feeders, billing). These unit costs, expressed as costs per customer, costs per kilowatt (kW) of demand, or costs per kilowatt hour (kWh) are then used to allocate the functional revenue requirements as described in PGE Exhibit 1300.

II. Generation Marginal Cost Study

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity, long-run marginal energy costs, and renewable energy requirements.

Q. Please describe the steps used to develop the long-run generation allocation methodology.

A. The generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used to provide both energy and capacity.
2. From this analysis, separately estimate the capacity and energy components as follows:
   a. Estimate the marginal cost of future capacity as the fixed cost of an "F-class" simple cycle combustion turbine (SCCT).
   b. Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
   c. Add 17% reserve requirements to the SCCT capacity costs consistent with PGE's 2016 Integrated Resource Plan (IRP).
3. Finally, express the capacity and energy values in real levelized terms.

Q. Has the methodology used to develop the long-run generation allocation changed since PGE's 2018 General Rate Case filed as Docket No. UE 319?

A. No.

Q. What are the sources of the overnight capital costs for the resources used in the model?

A. PGE's 2016 IRP is the source of the overnight capital costs[1] used in the analysis.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We weighted the marginal energy cost by the Renewable Portfolio Standard (RPS) target percentages for each year. For example, if the RPS target is 20% in a given year, the weighting is 20% wind and 80% thermal. The weightings reflect the revised RPS targets included in Senate Bill 1547.[2]

Q. What is the source of your long-term gas price forecast?

A. We used the Wood Mackenzie long-term gas price forecast dated November 2017 for the Sumas and AECO hubs, blended with near-term forward curves. We equally weighted the projected burner tip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. No. On both the national and state level, no carbon tax exists. Any potential future carbon tax is uncertain. The exclusion of carbon tax from this analysis is consistent with the treatment of carbon tax for purposes of PGE's avoided cost calculations used in Tariff Schedule 201.

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[1] Cost of the project as if no interest were included during its construction.
[2] 78th Oregon Legislative Assembly, 2016 Regular Session

Q. Did you include production tax credits in your analysis?

A. Yes. A production tax credit value of 60% was used, based on a resource that commences construction in 2018.

Q. What is the fully allocated cost of the wind farm?

A. The cost of the generic wind plant exclusive of wheeling is estimated at $42.05 per megawatt hour (MWh) in real levelized 2019 dollars.

Q. How did you estimate each rate schedule's long-run marginal cost of energy?

A. We multiply each schedule's monthly on-peak and off-peak load forecast by the corresponding monthly on-peak and off-peak long-term energy value.

Q. How do you shape the annual long-run marginal cost of energy into monthly on-peak and off-peak values?

A. We shape the annual long-run marginal energy cost into monthly on-peak and off-peak values based on the monthly on-peak and off-peak Mid-Columbia forward prices used in PGE's net variable power cost model (i.e., the Multi-area Optimization Network Energy Transaction model, also known as MONET[3]).

[3] See PGE Exhibit 300 for a description of MONET.

III. Transmission Marginal Cost Study

Q. Have you performed a transmission unit marginal costs analysis for this docket?

A. Yes. The methodology is the same as that used in UE 319. Based on the transmission project, contained in PGE Exhibit 1202, we calculate a unit marginal cost of $11.98/kW.[4]

Q. Is PGE a transmission-dependent utility?

A. Yes. PGE is a transmission-dependent utility that purchases about 3,700 megawatts (MW) of transmission from Bonneville Power Administration (BPA) to integrate its generation and purchased power. PGE operates a limited transmission system comprised of approximately 268 pole miles of 500 kilovolts (kV) lines and 270 pole miles of 230 kV lines, some of which is functionalized to generation. At the 230 kV level, the system ties into seven BPA bulk power substations around the Portland area. PGE also has ties into three BPA bulk power substations in the Salem area. The primary function of the 230 kV system that is functionalized to transmission is to provide an interface to the main grid for load service.

Q. What drives additions to PGE's existing transmission system?

A. PGE's transmission planners evaluate whether additions to PGE's existing transmission system are needed to meet North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) reliability standards for serving customers on the basis of 1-in-3 peak load conditions during the summer and winter seasons for both the near term and the long-term.[5] The winter period is defined as

[4] The transmission marginal cost value is shown in the provided transmission marginal cost study.
[5] Ibid, page 6.

November 1st through March 31st, and the summer is defined as June 1st through October 31st, therefore ten months in all. Because the transmission planners use ten months of peak loads when evaluating reliability, we extend the peak load criteria slightly to twelve months when calculating unit marginal costs. A twelve month criteria, or twelve coincident peak (12CP) is also consistent with how the Federal Energy Regulatory Commission (FERC) determines PGE's Open Access Transmission Tariff prices.

IV. Distribution Marginal Cost Study

Q. Which marginal distribution costs do you calculate?

A. We calculate marginal distribution costs separately for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers (including services), and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate the subtransmission unit costs using the subtransmission marginal investment cost from UE 319 escalated for inflation. We calculate substation marginal costs using a recent engineering estimate of the cost to construct a substation. We then divide the cost by the substation transformer capacity in kW, and annualize the cost per kW. Customers served at subtransmission voltage are excluded from this calculation because they supply their own substation. Columns (B) and (C) in PGE Exhibit 1201, page 3, summarize subtransmission and substation costs.

Q. How do you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers by class on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kV, and feeders that serve downtown core areas.

3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.
4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each customer class based on the customer class's proportionate contribution to non-coincident peak (NCP). Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each class's NCP.
6. For each feeder, allocate the tapline cost responsibility of each customer class based on its proportionate design demand (estimated peak at the line transformer). Calculate a unit cost per kW for both poly- and single- phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.
8. Separately estimate the unit costs of customers with peak loads greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the

substation and the customer-owned facilities. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per-customer costs of customers served at subtransmission voltage. This is done by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation. Then we multiply this average distance by the current cost per wire mile and annualize the costs.

Columns (D), (E), and (F) on page 3 of PGE Exhibit 1201 summarize feeder mainline and tapline costs.

Q. Why do you propose to calculate the marginal costs of feeders on the basis of class size rather than by rate schedule?

A. We propose this because past marginal feeder costs analyses have resulted in extremely high unit marginal costs for the irrigation Schedules 47 and 49 due to their preponderant location on remote feeders within PGE's service territory. This cost result for the irrigation schedules seems to be due to geographical distinction rather than due to economies of scale. Because PGE does not price by geographical area, we propose the class size distinction when calculating unit marginal feeder costs. For all other marginal cost categories, we separately measure the unit marginal costs of the irrigation schedules.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. Therefore, we used the current cost of underground facilities exclusively in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal transformer and service costs?

A. We calculate each schedule's marginal transformer and service costs by estimating the cost of providing the average customer within specific load sizes with a service lateral and a line transformer (secondary delivery voltage only). For smaller customers such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to appropriately calculate the per customer share of transformer costs. Column (G) on page 3 of PGE Exhibit 1201 summarizes transformer and service costs.

Because primary and subtransmission voltage customers supply their own transformer and service laterals, the marginal cost for these customers is zero.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the weighted installed cost of an Advanced Metering Infrastructure (AMI) meter for each rate schedule or load size, and then apply an annual carrying charge. Column (H) on page 3 of PGE Exhibit 1201 summarizes meter costs.

Q. How do you allocate distribution operations and maintenance (O&M) to each distribution category and ultimately to each rate schedule?

A. We allocate test-period distribution O&M by distribution category to the rate schedules in proportion to each schedule's respective usage and per unit marginal capital cost. All of the distribution costs by functional category, on page 3 of PGE Exhibit 1201, are inclusive of test-period distribution O&M.

Q. The UE 319 Partial Stipulation required PGE to evaluate the marginal capital costs of primary and secondary Distribution Facilities and the maintenance costs contained in FERC Account Nos. 583, 584, 593, and 594 and estimate the amounts attributable to secondary voltage service conductors, secondary voltage conductors, and primary voltage conductors. Has PGE met this requirement?

A. Yes. In consultation with Service and Design Project Managers, who in turn spoke with field personnel, we estimated the percentage of time field personnel spend on maintaining secondary service conductors. After estimating the approximate $6.1 million costs of maintaining secondary service conductors by the appropriate Accounting Work Order (AWO), we deduct the estimated secondary service conductor maintenance cost amounts from the total of the FERC maintenance amounts. Then, for the appropriate cost categories, we allocate the amount of expense attributable to primary voltage and secondary voltage conductors by the objective measure of relative circuit wire miles. This decomposition of the FERC maintenance accounts is contained in the feeder O&M work papers accompanying this filing. In addition to the allocation of maintenance costs described above, we reassigned approximately $60,000 in transformer costs from overhead and underground line maintenance to the transformer maintenance account.

Column (F) on page 3 of PGE Exhibit 1201 summarizes secondary distribution facilities costs.

Q. Please explain how this impacts the maintenance cost of secondary conductors.

A. PGE allocates its projected test period distribution feeder maintenance costs on the basis of each schedule's marginal costs; hence, attributing primary voltage and secondary voltage conductor maintenance costs separately will result in changes in how test period distribution feeder maintenance costs are allocated to the rate schedules. Primary voltage conductor maintenance costs are allocated to mainline feeders and local facilities. Secondary voltage conductor maintenance costs are allocated to local facilities based on the estimated percentage of secondary voltage conductors serving each rate schedule. This results in higher allocated test period maintenance costs to customers using secondary facilities.

V. Customer Service Marginal Cost Study

Q. What is the purpose of the customer service marginal cost study?

A. The purpose is to calculate the incremental cost of customer service for each rate schedule. PGE incurs costs in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing. As such, customer service costs increase as the number of customers PGE serves increases. Column (I) on page 3 of PGE Exhibit 1201 summarizes marginal customer costs.

Q. Does PGE use the forecasted test year expenses in the customer marginal cost study?

A. Yes. PGE uses forecasted costs for the 2018 test period and 2017 actual costs to develop the 2019 test year Customer Service Marginal Cost Study. These costs are found in FERC Account Nos. 902, 903, 905, 908, and 909. The 2019 forecasted costs are also referred to as budget amounts in this testimony.

Q. Is the study's methodology the same as in PGE's last rate case – UE 319?

A. Yes, the methodology is the same. As in UE 319, the costs are allocated by PGE accounts directly on the basis of cost causation. A few accounts are allocated based on a sub-allocation of the other account costs. After the costs are spread across rate schedules, the final result is marginal costs for each rate schedule by each of the three functionalized categories: metering, billing, and other services.

Q. Please provide an example of how you calculate metering marginal costs.

A. The 2019 forecasted amount for FERC Account No. 902, Field Collection Department, is allocated based on manual meter reads and a weighted percentage of customers (less unmetered lighting and signals).

Q. Please provide examples of how you calculate billing marginal costs.

A. Examples include:

- The costs for Retail Receivables and Field Collections are allocated based on percentage of adjusted write-offs by rate schedule.
- Customer Information System billing costs are allocated by the number of customers, except streetlights and traffic signals.
- The costs for Printing and Automated Mail Services are allocated based on the number of paper bills delivered.
- Network Data Operation costs are allocated based on the number of customers with meters, which excludes unmetered lighting and traffic signals.

Q. Please provide examples of how you calculate other customer service marginal costs.

A. Examples include:

- The budget amount associated with the Customer Contact Operations is allocated by the number of customers on rate schedules using up to 200 kW.
- The budget amount for the Direct Access Operations Department is allocated by the number of customers participating in the direct access program.

- The budget amount for the Special Attention Operations Department is allocated based on the number of residential customers.
- The Solar Payment Option and Net Metering Operations budget amounts are allocated by the number of customers participating in the programs.

VI. Area and Streetlights

Q. Please describe how you price Area Lights and Streetlights.

A. We price the investment portion (i.e., poles and luminaires) of providing lighting service using a real levelized annual revenue requirement. Lighting schedule prices will be updated to reflect the Cost of Capital adopted by the Commission in this proceeding.

Q. Please describe how you calculate the amount of outdoor lighting maintenance.

A. Similar to UE 319, we propose to base the test period lighting maintenance amount on the incurred maintenance amounts during PGE's most recent complete 5-year relamping cycle (2005-2009), before conversion to Light-Emitting Diode (LED) area and streetlights commenced. More specifically, we express the historical maintenance amounts on a per-light basis, and then escalate this per-light maintenance figure for inflation. A further reduction is made for LED street and area lights since (1) their maintenance is significantly less than other lights, and (2) the years used in the most recent 5-year re-lamping cycle do not include LEDs. Following this, we allocate maintenance to each type of luminaire based on the marginal cost of maintenance study.

Q. Do you provide a summary exhibit of the proposed pole and luminaire prices?

A. Yes. This summary is provided in PGE Exhibit 1305.

VII. Qualifications

Q. Mr. Goodspeed, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree in Public Policy from Washington State University and a Master of Business Administration degree from the University of New Orleans. I accepted my current role at PGE in 2016, and have previously worked in Senior Pricing Analyst and Pricing Lead roles for Entergy Services, Inc., providing pricing and rate design support to Entergy Louisiana LLC., Entergy Texas Inc., Entergy New Orleans Inc., and Entergy Arkansas Inc. I have also served as a financial analyst in Entergy's nuclear organization.

Q. Mr. Macfarlane, please state your educational background and experience.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in Finance. I have been Interim Manager, Pricing and Tariffs since January of 2018. My prior title was Regulatory Consultant. Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have included pricing, revenue requirement, Public Utility Regulatory Policies Act avoided costs, and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

Q. Does this conclude your testimony?

A. Yes.

VIII. List of Exhibits

PGE Exhibit	Description
1201	Marginal Cost Study
1202	PGE's Draft Near Term Local Transmission Plan

PORTLAND GENERAL ELECTRIC
2019 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,017,734	$303,025,693
Schedule 15	16,701	$567,660
Schedule 32	1,700,609	$63,345,918
Schedule 38	32,692	$1,260,508
Schedule 47	23,002	$874,342
Schedule 49	69,419	$2,638,126
Schedule 83	2,946,960	$110,562,096
Schedule 85	2,944,147	$109,544,583
Schedule 89	541,085	$19,873,332
Schedule 90-P	1,850,474	$67,405,013
Schedule 91/95	57,146	$1,942,392
Schedule 92	2,667	$96,756
TOTALS	18,202,636	$681,136,419

PORTLAND GENERAL ELECTRIC
2019 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2019	106.42	34.08	42.05	15.00%	106.42	35.28
2020	108.54	34.76	42.89	20.00%	108.54	36.39
2021	110.71	35.46	43.75	20.00%	110.71	37.11
2022	112.92	36.16	44.62	20.00%	112.92	37.86
2023	115.18	36.89	45.51	20.00%	115.18	38.61
2024	117.48	37.62	46.42	20.00%	117.48	39.38
2025	119.83	38.38	47.35	27.00%	119.83	40.80
2026	122.23	39.14	48.30	27.00%	122.23	41.61
2027	124.67	39.93	49.26	27.00%	124.67	42.45
2028	127.16	40.72	50.25	27.00%	127.16	43.29
2029	129.70	41.54	51.25	27.00%	129.70	44.16
2030	132.29	42.37	52.28	35.00%	132.29	45.84
2031	134.94	43.21	53.32	35.00%	134.94	46.75
2032	137.63	44.08	54.39	35.00%	137.63	47.69
2033	140.38	44.96	55.47	35.00%	140.38	48.64
2034	143.19	45.86	56.58	35.00%	143.19	49.61
2035	146.05	46.77	57.71	45.00%	146.05	51.70
2036	148.97	47.71	58.87	45.00%	148.97	52.73
2037	151.95	48.66	60.04	45.00%	151.95	53.78
2038	154.98	49.63	61.24	45.00%	154.98	54.86
Real Levelized	$106.42	$34.08	$42.05		$106.42	$36.31
NPV	$1,360	$436	$538		$1,360	$464
Nominal Levelized	$124.05	$39.73	$49.02		$124.05	$42.33
Real Levelized	$106.42	$34.08	$42.05		$106.42	$36.31

Composite Income Tax Rate			27.15%
Property Tax Rate			1.45%
Inflation Rate			2.00%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.50%	4.75%
All Equity	50.00%		4.75%
Debt	50.00%	4.97%	2.49%
Cost of Capital			7.24%
After-Tax Nominal Cost of Capital			6.56%
After-Tax Real Cost of Capital			4.47%

PORTLAND GENERAL ELECTRIC
SUMMARY OF TRANSMISSION, DISTRIBUTION AND CUSTOMER MARGINAL COST STUDIES

SCHEDULE	TRANSMISSION COSTS ($/kW)	SUBTRANSMISSION COSTS ($/kW)	SUBSTATION COSTS ($/kW)	FEEDER MAINLINE COSTS ($/kW)	FEEDER TAPLINE COSTS ($/kW)	SECONDARY TAPLINE COSTS ($kW)	TRANSFORMER & SERVICE COSTS ($/Customer)	METER COSTS ($/Customer)	CUSTOMER COSTS ($/Customer)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Schedule 7 Residential									
Single-phase	$11.98	$12.15	$12.24	$20.41	$15.71	$4.39	$83.97	$19.43	$63.37
Three-phase	$11.98	$12.15	$12.24	$20.41	$15.71	$4.39	$140.51	$58.07	$63.37
Schedule 15 Residential	$11.98	$12.15	$12.24	$21.38	$18.06	$2.72	$2.89	N/A	$11.23
Schedule 15 Commercial	$11.98	$12.15	$12.24	$21.38	$18.06	$2.72	$2.89	N/A	$13.01
Schedule 32 General Service									
Single-phase	$11.98	$12.15	$12.24	$24.70	$23.90	$3.34	$150.15	$17.23	$80.60
Three-phase	$11.98	$12.15	$12.24	$24.70	$11.35	$1.59	$236.86	$72.71	$80.60
Schedule 38 TOU									
Single-phase	$11.98	$12.15	$12.24	$24.54	$24.34	$2.04	$196.72	$58.07	$162.10
Three-phase	$11.98	$12.15	$12.24	$24.54	$12.08	$1.01	$581.00	$130.80	$162.10
Schedule 47 Irrigation									
Single-phase	$11.98	$12.15	$12.24	$24.70	$23.90		$10.77	$57.73	$79.11
Three-phase	$11.98	$12.15	$12.24	$24.70	$11.35		$21.43	$86.54	$79.11
Schedule 49 Irrigation									
Single-phase	$11.98	$12.15	$12.24	$24.54	$24.34		$144.93	$58.07	$147.14
Three-phase	$11.98	$12.15	$12.24	$24.54	$12.08		$144.93	$71.36	$147.14
Schedule 83 Secondary General Service									
Single-phase	$11.98	$12.15	$12.24	$24.54	$24.34	$2.04	$388.14	$57.73	$249.80
Three-phase	$11.98	$12.15	$12.24	$24.54	$12.08	$1.01	$1,050.66	$129.44	$249.80
Schedule 85 Secondary General Service	$11.98	$12.15	$12.24	$19.54	$7.12		$2,419.89	$162.33	$1,315.52
Schedule 85 Primary General Service	$11.98	$12.15	$12.24	$19.54	$7.12		$0.00	$1,805.54	$1,315.52
Schedule 89 Secondary	$11.98	$12.15	$12.24	$76,614 ($/Customer)	N/A		$14,124.26	$175.85	$9,594.75
Schedule 89 Primary	$11.98	$12.15	$12.24	$76,614 ($/Customer)	N/A		$0.00	$1,809.13	$9,594.75
Schedule 89 Subtransmission	$11.98	$12.15	N/A	$77,041 ($/Customer)	N/A		N/A	$19,774.56	$9,594.75
Schedule 90 Primary	$11.98	$12.15	$12.24	$365,087	NA		$0.00	$1,805.54	$33,539.76
Schedules 91 & 95 Streetlighting	$11.98	$12.15	$12.24	$21.38	$18.06	$5.05	$2.89	N/A	$989.77
Schedules 92 Traffic Signals	$11.98	$12.15	$12.24	$21.38	$10.30	$0.14	$9.19	N/A	$986.10

Portland General Electric Company's Longer Term Local Transmission Plan For the 2016-2017 Planning Cycle

December 28, 2017

Contents

1. Introduction

This 2017 Longer Term Local Transmission Plan reflects Quarters 5 through 8 of the local transmission planning process as described in PGE's Open Access Transmission Tariff (OATT) Attachment K. The plan includes all transmission system facility improvements identified through this planning process. A power flow reliability assessment of the plan was performed which demonstrated that the planned facility additions will meet NERC and WECC reliability standards.

PGE's OATT is located on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the *Transmission Planning* folder on PGE's OASIS. Unless otherwise specified, capitalized terms used herein are defined in PGE's OATT.

1.1. Local Planning

This Local Transmission Plan (LTP) has been prepared within the two-year process as defined in PGE's OATT Attachment K. The LTP identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed. However, none were requested or incorporated during this particular cycle.

Projects identified in the Longer Term Local Transmission Plan's six (6) to ten (10) year planning horizon are not committed projects and are subject to modification and/or withdrawal. Projects described herein are not part of PGE's Expansion Plan as described in Section 12.2.3 of Attachment O to PGE's OATT.

1.2. Regional and Interregional Coordination

PGE coordinates its planning processes with other transmission providers through membership in the Northern Tier Transmission Group (NTTG) and the Western Electric Coordinating Council (WECC). PGE uses the NTTG process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is located in PGE's OATT Attachment K, in our Transmission Planning Business Practice on OASIS, and on the NTTG's website at www.nttg.biz.

2. Planning Process and Timeline

This plan is for the 2016-2017 planning cycle. PGE's OATT Attachment K describes an eight (8) quarter study and planning cycle. The planning cycle schedule is shown below in Figure 1.

Figure 1: PGE OATT Attachment K Eight Quarter Planning Cycle

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Near Term methodology on OASIS, select one Economic Study for evaluation
		3	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and/or progress made under the Attachment K planning process, during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the *Customer Meetings* folder on PGE's OASIS. Figure 2 shows the meetings held in 2017 and the meetings scheduled for 2018.

Figure 2: Quarterly Customer Meetings

Planning Cycle Quarter	Meeting Date
5	March 7, 2017
6	June 6, 2017
7	September 12, 2017
8	*December 5, 2017*
1	*March 13, 2018*
2	*June 12, 2018*
3	*September 11, 2018*
4	*December 11, 2018*

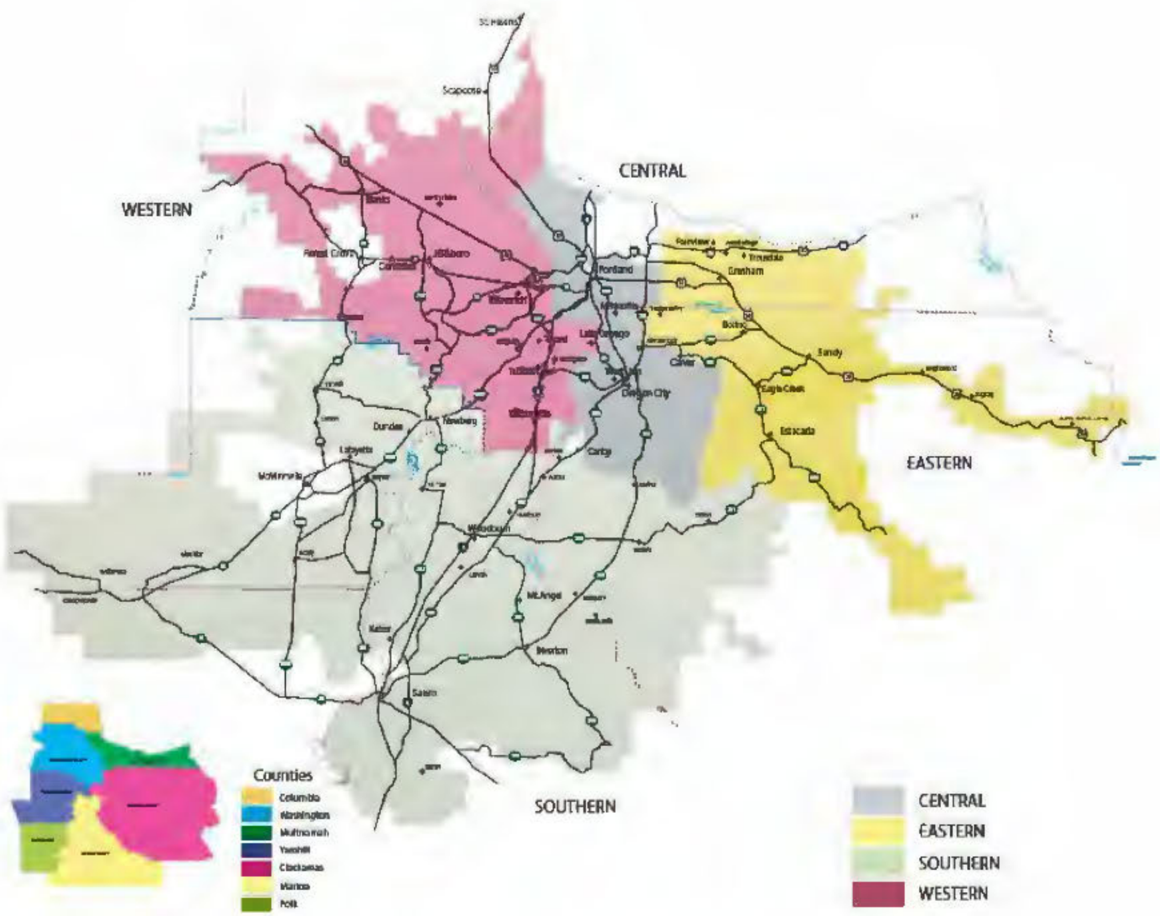
*Meeting dates in *italics* are upcoming and subject to change.

3. Transmission System Plan Inputs and Components

3.1. PGE's Transmission System

Portland General Electric's (PGE) service territory covers more than 4,000 square miles and provides service to over 825,000 customers. PGE's service territory is confined within Multnomah, Washington, Clackamas, Yamhill, Marion, and Polk counties in northwest Oregon, as shown in Figure 3.

Figure 3: Map of PGE's Service Territory



PGE's Transmission System is designed to reliably distribute power throughout the Portland & Salem regions for the purpose of serving native load. In addition to the load-service transmission facilities, PGE also maintains ownership of networked Transmission System circuits (See Figure 4) used to integrate transmission and generation resources on the Bulk Electric System.

Figure 4: PGE-Owned Transmission System Circuits

Transmission Circuit	Circuit Miles	Transmission Path
Grizzly-Malin 500kV	178.5 miles	COI[1]
Grizzly-Round Butte 500kV	15.6 miles	
Colstrip-Townsend #1 500kV	37.3 miles (15% ownership)	
Colstrip-Townsend #2 500kV	36.9 miles (15% ownership)	
Bethel-Round Butte 230kV	99.2 miles	WOCS[2]
St Marys-Trojan 230kV	41.4 miles	SOA[3]
Rivergate-Trojan 230kV	35.1 miles	SOA

In total, PGE owns 1,590 circuit miles of sub-transmission/transmission at voltages ranging from 57kV to 500kV. (See Figure 5)

Figure 5: PGE Circuit Miles Owned (By Voltage Level)

Voltage Level	Pole Miles	Circuit Miles
500 kV	268	268
230 kV	270	319
115 kV	496	551
57 kV	430	451

3.2. Load Forecast

For load forecasting purposes, PGE's transmission system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for Near Term (years 1 through 5) and Longer Term (years 6 through 10) studies.

The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's T&D System to its customers. PGE defines the seasons to align with the Peak Reliability Seasonal System Operating Limits Coordination Process, Appendix 'V'.

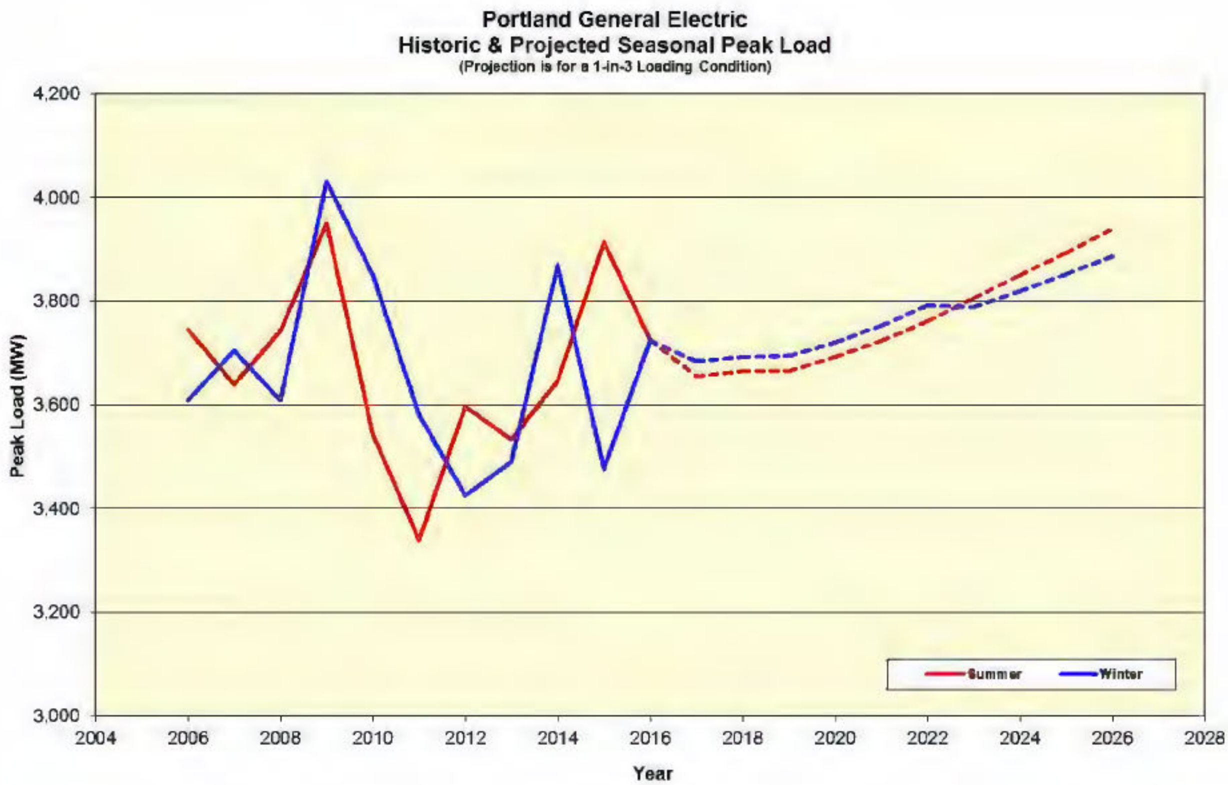
[1] California-Oregon Intertie
[2] West of Cascades South
[3] South of Allston

Figure 6: Summer/Winter Loading Conditions and Corresponding Daily-Averaged Temperatures

Summer	
1-in-2	79°F
1-in-3	81°F
1-in-5	83°F
1-in-10	85°F
1-in-20	87°F

Winter	
1-in-2	28°F
1-in-3	24°F
1-in-5	21°F
1-in-10	18°F
1-in-20	15°F

Figure 7: Portland General Electric's Historic & Projected Seasonal Peak Load
(Projection is for a 1-in-3 Loading Condition)



As depicted in Figure 7, PGE's all-time peak load occurred on December 21, 1998, with the Net System Load[4] reaching 4073 MW. PGE's all time summer peak occurred on July 29, 2009 with the Net System Load reaching 3949 MW.

[4] The Net System Load is the total load served by PGEM, including losses. This includes PGE load in all control areas, plus ESS load, minus net borderlines.

3.3. Forecasted Resources

The forecasted resources are comprised of generators, identified by network customers as designated network resources, that are integrated into the wider regional forecasts of expected resources committed to meet seasonal peak loads.

3.4. Economic Studies

Eligible customers or stakeholders may submit economic congestion study requests during either Quarter 1 or Quarter 5 of the planning cycle. However, PGE did not receive any study requests during the 2016-2017 planning cycle.

3.5 Stakeholder Submissions

Any stakeholder may submit data to be evaluated as part of the preparation of the draft Longer Term Local Transmission Plan and/or the development of sensitivity analyses, including alternative solutions to the identified needs set out in prior Local Transmission Plans, Public Policy Considerations and Requirements, and transmission needs driven by Public Policy Considerations and Requirements. However, PGE did not receive any such data submissions during the 2016-2017 planning cycle.

4. Methodology

PGE's transmission system is designed to reliably supply projected customer demands and projected Firm Transmission Services over the range of forecasted system demands. Studies are performed annually to evaluate where transmission upgrades may be needed to meet performance requirements.

PGE maintains system models within its planning area for performing the studies required to complete the System Assessment. These models use data that is provided in WECC Base Cases in accordance with the MOD-010-0 and MOD-012-0 reliability standards. Electrical facilities modeled in the cases have established normal and emergency ratings, as defined in PGE's Facility Ratings Methodology document. A facility rating is determined based on the most limiting component in a given transmission path, in accordance with the FAC-008-3 reliability standard.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 115kV transmission system (primarily auto mode - time-clock; two auto mode - voltage control) and on the 57kV transmission system (auto mode - voltage control).

Studies are evaluated for the Near Term Planning Horizon (years 1 through 5) and the Longer Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load model used in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-3 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. Transmission equipment is assumed to be out of service in the Base Case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

In the Near Term, studies are performed for the following:

- System Peak Load for either Year One or Year Two
- System Peak Load for Year Five
- System Off-Peak Load for one of the five years

Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE alters the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak system sensitivity cases, the 1-in-10 load forecast is used.

Studies are evaluated at peak summer and peak winter load conditions for one of the years in the Longer Term Planning Horizon.

Figure 8: Powerflow Base Cases Used in 2017 Assessment

		Study Year	Origin WECC Base Case	PGE Case Name	PGE System Load (MW)
SUMMER	Year One/Two Case	2019	2021 HS2	19 HS PLANNING	3665
	Year Five Case	2022	2022 HS1	22 HS PLANNING	3762
	Year One/Two Sensitivity	2019	2021 HS2	19 HS SENSITIVITY	3789
	Year Five Sensitivity	2022	2022 HS1	22 HS SENSITIVITY	3889
	Long Term Case	2027	2027 HS1	27 HS PLANNING	3986
WINTER	Year One/Two Case	2018-19	2020-21 HW1	18-19 HW PLANNING	3694
	Year Five Case	2022-23	2021-22 HW2	22-23 HW PLANNING	3792
	Year One/Two Sensitivity	2018-19	2020-21 HW1	18-19 HW SENSITIVITY	3879
	Year Five Sensitivity	2022-23	2021-22 HW2	22-23 HW SENSITIVITY	3981
	Long Term Case	2027-28	2026-27 HW1	27-28 HW PLANNING	3921
SPRING	Near Term Off Peak Case	2019	2017 LSP2-S	19 LSP PLANNING	2427
	Near Term Off Peak Sensitivity	2019	2017 LSP2-S	19 LSP SENSITIVITY	2427

The Bulk Electric System is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-4 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-4 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

4.1. Steady State Studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all contingency scenarios identified in Table 1 of the NERC TPL-001-4 reliability standard to determine if the Transmission System meets performance requirements. These studies also assess the impact of Extreme Events on the system expected to produce severe system impacts.

The contingency analyses simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to voltage limitations and tripping of transmission elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

Capacity addition projects are developed when simulations indicate the system's inability to meet the steady-state performance requirements for P1 events. For P2-P7 events, PGE identifies distribution substations where manual post-contingency "load-shedding" may be required to ensure that the Transmission System remains within the defined operating limits.

4.2. Transient Stability Studies

PGE evaluates the voltage and transient stability performance of the Transmission System for contingencies to PGE and adjacent utility equipment at 500kV and 230kV. The studies evaluate single line-to-ground and 3φ faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit transmission line. Extreme events are studied for 3φ faults with Delayed Fault Clearing.

For all 500kV and 230kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the protection system operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500kV and 230kV facilities; and the majority of 115kV facilities. Delayed clearing occurs when a breaker fails to operate and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the contingency definition.

The transient stability results are evaluated against the performance requirements outlined in the NERC TPL-001-4 reliability standard and against the WECC Disturbance-Performance Table of Allowable Effects on Other Systems (Table I). The simulation durations are run to 20 seconds.

Figure 9: WECC Disturbance-Performance Table of Allowable Effects on Other Systems[5]

WECC and NERC Categories	Outage Frequency Associated with the Performance Category	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
A (P0)	Not Applicable	Nothing in addition to NERC		
B (P1)	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C (P2-P7)	0.033-0.33	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D (Extreme)	< 0.033	Nothing in addition to NERC		

Contingency analyses simulate the removal of all elements that the Protection System and other automatic controls expected to disconnect for each contingency without Operator intervention. The analyses include the impact of the subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized
- Tripping of generators due to voltage limitations
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models
- Automatic controls simulated include generator exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

Cascading is not allowed to occur for any contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

5 The WECC TPL-001-WECC-CRT Regional Criterion is currently undergoing a revision to adapt the new categories (P0-P7) in the NERC TPL-001-4 reliability standard.

Corrective Action Plans are developed if the stability studies indicate that the system cannot meet the TPL-001-4 and WECC performance requirements.

- P1: No generating unit pulls out of synchronism
- P2-P7: When a generator pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities
- P1-P7: Power oscillations exhibit acceptable damping

5. Results

5.1. Steady State Results – Longer Term Evaluation

There are no contingency loading or voltage concerns on PGE's system in the Longer Term Planning Horizon for NERC TPL-001-4 Categories P1, P2, P3, P4, and P5. NERC TPL-001-4 Category P6 and P7 contingency overloads and voltage concerns are addressed with load shedding, as permitted, on PGE's local distribution system. None of the contingencies evaluated will result in cascading from PGE's Control Area to another Control Area.

5.2. Longer Term Transient Stability

The Longer Term transient stability studies indicate that PGE's Transmission System exhibits adequate transient stability throughout the 500kV and 230kV transmission systems. The minimum transient frequency response recorded did not dip below 59.6 Hz for any of the contingency events studied on PGE's Transmission System. Underfrequency Load Shedding ("UFLS") relays are not affected because the set point for UFLS relays is 59.3 Hz. The transient voltage dip did not exceed 25% at any load bus or 30% at any non-load bus for any of the contingency events studied on PGE's Transmission System. 5.3. Projects Currently Included in the Longer Term Plan

There are 3 projects currently planned for implementation in the Longer Term Planning Horizon.

Projects described in this Longer Term Plan are subject to modification and/or withdrawal.

Potential projects are described in detail in Appendix A.

Appendix A: 10 Year Project List

Potential projects currently included in the Longer Term Plan are:

- Lower Columbia Resiliency Project
- North Hillsboro Capacity Project
- Orenco-Sunset 115kV Reconductor Project

These projects are described in more detail on the following pages.

Lower Columbia Resiliency Project

- **Project Purpose**
    - Increase transfer capacity into the Portland area via the South of Allston transfer path
- **Project Scope**
    - Construct a new 230kV transmission line from Trojan substation to Harborton Substation
- **Project Status**
    - Preliminary planning
- **Project Requirement Date**
    - No date established; TBD

North Hillsboro Capacity Project

- **Project Purpose**
  - Increase capacity in the North Hillsboro area

- **Project Scope**
  - Construct a new 230kV substation in the north Hillsboro area
  - Loop the Harborton-Horizon 230kV line into the new substation
  - Install a 230/115 kV bulk power transformer at the new substation
  - Loop the Shute-West Union 115kV line into the new substation
  - Reterminate the Shute substation end of the Shute-Sunset #1 115kV line at the new substation

- **Project Status**
  - Preliminary planning

- **Project Requirement Date**
  - No date established; TBD

Orenco-Sunset 115kV Reconductor Project

- **Project Purpose**
  - Increase the capacity of the Orenco-Sunset 115kV line to eliminate thermal overload concerns

- **Project Scope**
  - Reconductor the Orenco-Sunset 115kV circuit (approx. 3 miles) to 795 ACSS.

- **Project Status**
  - Preliminary planning

- **Project Requirement Date**
  - No date established; TBD

Northern Substation 115kV Conversion Project

- **Project Purpose**
  - Upgrade the Northern substation and convert it to 115kV

- **Project Scope**

  The Curtis-Rivergate #2 115kV circuit will be looped in to the new breaker station, creating a Curtis-Northern 115kV circuit and a Northern-Rivergate 115kV circuit.

- **Project Status**
  - Preliminary planning

- **Project Requirement Date**
  - No date established; TBD

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Robert Macfarlane
Jacob Goodspeed

February 15, 2018

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am Interim Manager, Pricing and Tariffs for Portland General Electric Company (PGE).

My name is Jacob Goodspeed. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE.

Our qualifications are described in PGE Exhibit 1200.

Q. What is the purpose of your testimony?

A. Our testimony and accompanying exhibits demonstrate how the proposed E-18 Tariff changes recover PGE's 2019 revenue requirement in a way that achieves fair, just, and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, our testimony also describes the revenue requirement allocation process (i.e., ratespread), and the rate design. We also:

1. Support changes to PGE's decoupling mechanism Schedule 123;
2. Introduce Schedule 132 to refund the effects associated with the changes in federal taxes consistent with PGE's deferred accounting application covering the period through year-end 2018, Docket No. UM 1920;
3. Review language changes to Schedule 122, Renewable Resources Automatic Adjustment Clause, to include energy storage;
4. Support changes to the blocking associated with Schedule 102 residential customers;
5. Summarize the update to prices contained in Schedule 300, Charges as Defined by the Rules and Regulations and Miscellaneous Charges; and

6. Propose two changes to PGE's long-term direct access program.

Q. Please summarize the projected Cost of Service (COS) rate impacts resulting from the proposed allocations.

A. Table 1 below summarizes the base rate impacts for the major rate schedules and the overall impact. PGE Exhibit 1302 contains more detailed information on the rate impacts for the individual schedules. Table 1 of PGE Exhibit 1302 contains the base rate impacts of the proposed prices effective January 1, 2019. The detailed bill impacts starting on page 2 of PGE Exhibit 1302 relate to prices effective January 1, 2019, inclusive of the estimated changes in supplemental schedules known at this time.

Table 1
Estimated Cost of Service Base Rate Impacts Inclusive of Schedule 122

Schedule	Jan. 1, 2019
Schedule 7 Residential	6.3%
Schedule 32 Small Nonresidential	7.1%
Schedule 83 31-200 kW	3.8%
Schedule 85 201-4,000 kW	1.2%
Schedule 89 Over 4,000 kW	2.1%
Schedule 90 100 MWa	3.2%
COS & DA Overall	4.8%

II. UE 319 Stipulations

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of testimony is to discuss treatment of specific items in the stipulations from PGE's previous general rate case, Docket No. UE 319 (UE 319).

Q. Please summarize the items you address.

A. We address the following items:

- Schedule 32 demand charges;
- Schedule 90 load following credit;
- Customer impact offset (CIO) for lighting schedules; and
- CUB's energy efficiency (EE) issue.

Q. What did the first UE 319 stipulation direct PGE to address regarding demand charges for Schedule 32?

A. The stipulation directs PGE to either propose demand charges for Schedule 32 or explain why demand charges are not appropriate for Schedule 32.

Q. Do you propose to implement demand charges for Schedule 32?

A. No. The downside of using demand charges in the design of small residential customer prices is not outweighed by any benefits. The downsides include the impact of demand charges (versus volumetric) on EE, impact on small business electric vehicle charging, and customer understanding of price design.

PGE doesn't have any demand charges relating to generation, it only has demand charges for transmission and distribution for most large nonresidential customers. Volumetric charges for small nonresidential customers encourage energy conservation, are simple and understandable, and customers prefer volumetric prices for electric vehicle charging. The

Public Utility Commission of Oregon (Commission) differentiates between small nonresidential (demand of 30 kilowatts (kW) or less) and large nonresidential (demand greater than 30 kW) customers, providing small nonresidential customers the same options in many cases as residential customers under Division 38 of the Oregon Administrative Rules. The small nonresidential customers on Schedule 32 represent the largest number of customers on any of PGE's nonresidential rate schedules and include many small businesses. In addition, PGE provides an option (optional Schedule 38) for its next larger nonresidential customers (Schedule 83, demand 31kW to 200 kW) that includes volumetric charges rather than demand charges. It's difficult to justify demand charges for customers 30 kW and under while providing an optional volumetric schedule for customers with demand greater than 30 kW.

Demand charges provide an incentive to reduce peak demand and shift load to off-peak hours. However, they do not encourage EE to the extent that volumetric prices encourage EE. For this group of customers, a simple and understandable pricing structure is important. Unlike some of PGE's larger customers, Schedule 32 customers don't typically have energy managers to advise them and explain price structures. In addition, the schedule is used for electric vehicle (EV) charging. PGE continues to provide an option for its next larger nonresidential customers (Schedule 38) that includes volumetric charges rather than demand charges, in part, because customers use it for EV charging.

Q. What did the first UE 319 stipulation direct PGE to do regarding the Schedule 90 load following credit.

A. For purposes of UE 319, the stipulation adopted Industrial Customers of Northwest Utilities' (ICNU) proposal to credit Schedule 90 with 1.13 mills/kWh plus another 0.25 mills/kWh for

150 MW of flat energy. The remaining COS schedules were allocated the costs of providing the 1.13 mills/kWh credit, with Schedule 89 COS customers also allocated all of the costs of providing the additional 0.25 mills/kWh credit, limited to providing Schedule 89 with a surcharge not to exceed 0.57 mills/kWh. However, the stipulation did not require a specific load following methodology beyond UE 319.

Q. Do you propose a Schedule 90 load following credit for this general rate case?

A. Yes, we propose to carry forward the load following credit to Schedule 90 of 1.13 mills/kWh for 150 MW of flat energy. The remaining COS schedules are allocated the costs of providing the 1.13 mills/kWh credit. In addition, we propose the additional credit of 0.25 mills/kWh provided by Schedule 89 COS customers.

Q. What did the second UE 319 stipulation specify regarding the CUB EE issue?

A. The stipulation directed PGE to provide a CIO, with customers on Schedules 7 and 32 receiving $777,315 on an equal cents/kWh basis. The amount is an approximation of the revenue requirement allocated to residential customers with and without load served by EE. To pay for the CIO, (a) $618,652 is allocated to Schedules 89/489/589 on an equal cents/kWh basis, and (b) $154,663 is allocated to Schedules 90/490/590 on an equal cents/kWh basis.

The Stipulating Parties requested that the Commission open an investigation into the funding of EE and the allocation of costs and benefits among rate classes. The parties requested that the investigation include an evaluation of the sources and relative costs of EE “megaprojects” acquired by Energy Trust of Oregon (ETO). The Stipulation provided that once the Commission issues an order in the docket, PGE is to implement the Commission’s recommendation in its next general rate case following that order.

During the pendency of the docket described above, PGE is to implement the CIO stipulation as described above. The stipulation includes other provisions relating to when the stipulating parties will and will not make proposals relating to funding EE and the costs and benefits of EE. The stipulation also raises ETO's informal cap on public purpose charge funding for customers over 1 average megawatt (MWa) in PGE's service territory.

Q. What do you propose to address the stipulation regarding the CUB EE issue in this docket?

A. We propose to continue the CIO in the manner described above and as implemented in UE 319.

III. Ratespread

Q. What is the basis for the functional allocation of costs to the rate schedules?

A. We use the Marginal Cost of Service Study to guide the allocation of the generation, transmission, distribution, and customer service (separately, Metering, Billing, and Other Consumer Services) functional revenue requirements in the ratespread process. The Marginal Cost of Service Study is presented in PGE Exhibit 1200.

Q. How do you calculate and allocate the 2019 test-period marginal generation capacity costs to the individual rate schedules?

A. To obtain the marginal generation capacity costs, we multiply the real levelized annual capacity cost described in PGE Exhibit 1200 by the projected 2019 COS test-period peak-hour load. This peak-hour load is projected to occur in December. We then allocate the marginal generation capacity costs on the basis of each schedule's relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-coincident peak or 4CP).

Q. Why do you choose these four months?

A. We choose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2016 Integrated Resource Plan. Additionally, we choose these four months because PGE's highest annual peak hours generally occur during one of these four months.

Q. What are the respective capacity and energy percentages used in allocating the generation revenue requirements?

A. Capacity comprises approximately 34.3% of the marginal cost of generation, and energy approximately 65.7%. These figures reflect the inclusion of load following costs as a capacity cost. The corresponding figures from UE 319 were approximately 36.1% and 63.9%.

Q. How do you allocate the transmission revenue requirement?

A. As stated above, we allocate the transmission revenue requirement on the basis of each rate schedule's 12 monthly coincident peaks (12CP) times the unit marginal transmission costs presented in PGE Exhibit 1200.

Q. Parties to recent proceedings have argued that transmission lines functioning as generation leads should be allocated on the basis of both capacity and energy. Do you agree?

A. Yes.

Q. Please describe how PGE functionalizes transmission lines that serve as generation leads.

A. PGE functionalizes to generation the generation lead transmission lines such as the Colstrip transmission facilities and the Port Westward to Trojan lines. Hence, through the revenue requirement unbundling process, PGE ensures that generation lead transmission lines are allocated on the basis of both capacity and energy. Furthermore, PGE's wheeling expense of approximately $82 million from purchasing Bonneville Power Administration (BPA) transmission is functionalized to generation and allocated on the basis of energy and capacity in proportion to how the generation revenue requirement is allocated.

Q. Why is it appropriate to allocate PGE transmission costs to capacity?

A. It is appropriate because the transmission investment included in the marginal cost study is made as a function of peak loads. Furthermore, the transmission investments included in the transmission marginal cost study do not include generation lead transmission lines that are classified to generation and allocated on both energy and capacity bases. PGE functionalizes to generation the generation lead high voltage transmission facilities that bring major production sources to PGE's service territory. Those transmission facilities are functionalized to energy and capacity, following the generation allocation. For example, PGE integrates both of its coal plants, Boardman and Colstrip, and its Carty natural gas plant with BPA transmission. The cost of this transmission is contained in net variable power costs and is therefore functionalized to generation. Both the Colstrip transmission line and the Grassland switchyard, constructed to connect Carty to BPA's Slatt substation via the Boardman-Slatt generation lead, are also functionalized to the generation revenue requirement. As a result of this functionalization, the majority of the transmission used to bring Boardman, Carty, and Colstrip power to PGE's service territory is allocated on the basis of energy. The same is true of other PGE generating resources that use BPA transmission.

Q. What other functional revenue requirement categories do you allocate besides those mentioned above?

A. Because the Ancillary Services revenue requirement is split out from generation, we allocate it in the same manner as generation. The Ancillary Services functional category combined with the six categories above complete the seven functional categories specified in ORS 757.642.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. We allocate franchise fees to the schedules on the basis of the test period revenue requirement allocations and Trojan decommissioning on a generation revenue basis. We allocate Schedule 129, Long-Term Transition Adjustment, on an energy basis to all schedules. This allocation is consistent with the allocation used in recent general rate cases. Finally, we allocate uncollectible expense based on historical incidence for the years 2013-2017. All allocations are presented in PGE Exhibit 1304.

Q. Please describe how you allocate and price the recovery of franchise fees consistent with Commission Order No. 12-500.

A. We allocate franchise fees in the same manner as in UE 319 and other recent dockets. Therefore, we do not attribute cost responsibility for the generation and transmission functional categories to direct access customers. More specifically, we allocate the franchise fee revenue requirements by segregating the generation and transmission revenue requirement test-period allocations from the other revenue requirement allocations across the schedules and separately calculate the prices for each category of allocations. Because direct access customers do not pay generation and transmission charges to PGE, we calculate a franchise fee price differential related to these charges and apply this differential to the direct access schedules. This differential is inclusive of Schedule 129 revenues and is captured in the system usage charges for each direct access schedule. For direct access schedules that do not have an explicit system usage charge, we establish a price differential within the volumetric distribution charges.

Q. Do you propose any form of rate mitigation or other deviation from using marginal cost to spread the revenue requirement?

A. Yes, we make several changes from the initial allocation of revenue requirement. The first change is that we reallocate between Schedules 89 and 90 the initial transmission, ancillary service, and distribution cost allocations that comprise the transmission and distribution demand charges for the two schedules. The second change is that after spreading the revenue requirement, we equalize the Distribution charges for Schedules 15, 91, and 95 through the CIO. We do this for these outdoor lighting schedules because the services provided are so similar in nature.

Q. Why do you reallocate some of the initial transmission, ancillary, and distribution cost allocations between Schedules 89 and 90?

A. We reallocate the transmission, ancillary services, subtransmission, and substation costs between the two rate schedules because all of the cost categories are facilities with the same unit marginal cost. However, because Schedule 90 has only one customer with four accounts engaging in similar activity, there is virtually no diversity of the demand billing determinants relative to Schedule 89 that has multiple customers engaged in different manufacturing activities. The differences in diversity of demand billing determinants is important; although Schedule 90 has a higher non-coincident peak load factor than Schedule 89, and has relatively lower unit feeder costs (per kW) than Schedule 89, absent reallocating the cost categories above, Schedule 90 would have higher applicable distribution prices than Schedule 89 due to the relative lack of demand billing determinants over which to spread costs. Given that most of the cost categories above have the same unit costs, this result would not make intuitive sense. Therefore, we propose the reallocation of the above costs based on billing demand. We do not propose the reallocation of the other costs categories such as generation and customer service because these categories have their unique costs attributions that yield reasonable prices.

IV. Rate Schedule Design

Q. Please provide a brief summary of the major COS rate schedules.

A. There are six major (COS) rate schedules:

- **Schedule 7, Residential Service**, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and a two-block energy rate.
- **Schedule 32, Small Nonresidential Standard Service (30 kW or less)**, consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.
- **Schedule 83, Large Nonresidential Standard Service (31 kW to 200 kW)**, is applicable to all secondary voltage Large Nonresidential customers between 31 kW and 200 kW, except for certain specialty schedules. This schedule contains more complex charges than Schedules 7 and 32. In addition to the basic charges, there is a Transmission Demand Charge based on the highest metered kW reading for a 30-minute period during on-peak periods within the monthly billing cycle. There is also a Distribution Demand Charge based on the same criteria above, and a Distribution Facility Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). The Energy Charge is mandatory Time-of-Use (TOU).
- **Schedule 85, Large Nonresidential Standard Service (201 kW to 4,000 kW),** is applicable to secondary and primary voltage customers from 201 kW to 4,000 kW. The Schedule 85 Transmission and Distribution Demand

Charges as well as the Facility Capacity Charges are based on the same criteria as they are for Schedule 83. The proposed Energy Charges continue to be on- and off-peak differentiated.

- Schedule 89, Large Nonresidential Standard Service (>4,000 kW), applies to customers whose Facility Capacity exceeds 4,000 kW. This schedule contains Transmission and Distribution Demand Charges that are based on the 30-minute periods that occur during on-peak intervals. These on-peak intervals are defined as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89 Distribution Facility Capacity Charge billing determinant is calculated in the same manner as for Schedules 83 and 85. The Energy Charges will continue to be on- and off-peak differentiated.
- Schedule 90, Large Nonresidential (>4,000 kW, aggregating to exceed 100 MWa) applies to customers whose Facility Capacity exceeds 4,000 kW and whose aggregate energy consumption exceeds 100 MWa. The rate design is similar to Schedule 89, but with higher customer charges.

Q. What principles do you consider in developing the proposed prices?

A. We consider the following Bonbright[1] principles in both the cost allocation and pricing processes. The proposed prices should accomplish the following:

- Recover the total revenue requirement;
- Provide revenue stability and predictability to the utility;
- Provide rate stability and predictability to customers;
- Reflect the cost of providing service to the customer classes;

[1] "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

- Be fair to the customer classes;
- Send appropriate price signals; and
- Be simple and understandable.

Q. How do you develop the prices for each rate schedule?

A. We explain the development of prices for each of the major rate schedules below. PGE Exhibit 1303, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual monthly prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Table 2
Schedule 7 - Residential Service Proposed Prices

Category	**Prices**
Basic Charge	$13.00 per customer per month
Transmission & Related Service Charge	2.52 mills per kWh
Distribution Charge	46.88 mills per kWh
Energy Charge First 1,000 kWh	66.29 mills per kWh
Energy Charge Over 1,000 kWh	73.51 mills per kWh

Q. Please explain how you develop these prices.

A. Although the embedded customer costs suggest a **Basic Charge** of approximately $25, we propose to increase the Basic Charge by $2.00 monthly to $13.00 in order to better match prices to embedded costs, consistent with the principles discussed above. This approach balances the Bonbright principles of reflecting costs and sending the appropriate price signals for conservation.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 46.88 mills per kWh from the allocated distribution costs and from the allocated costs not recovered by the other charges. The

Distribution Charge also includes the allocation of franchise fees and Trojan Decommissioning costs.

We maintain the Schedule 7 blocked **Energy Charges** structure of under/over 1,000 kWh with a price differential of 7.22 mills per kWh.

Q. Do you incorporate a projection of the revenue impacts of the Schedule 7 voluntary portfolio TOU option in the calculation of the energy, transmission, and distribution prices?

A. Yes. We estimate that by continuing to price the voluntary TOU customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $359,000. We incorporate this impact in the standard Schedule 7 energy, transmission, and distribution charges.

Q. Please list the individual monthly prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Table 3
Schedule 32 - Small Nonresidential Service

Category	Prices
Basic Charge Single Phase	$20.00 per customer per month
Basic Charge Three Phase	$29.00 per customer per month
Transmission & Related Services Charge	2.12 mills per kWh
Distribution Charge First 5,000 kWh	45.45 mills per kWh
Distribution Charge Over 5,000 kWh	15.16 mills per kWh
Energy Charge	60.73 mills per kWh

Q. Please describe how you develop the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, with Facility Capacity less than or equal to 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage, and other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. To better reflect costs, we increase the Basic Charge for single- and three-phase service to $20.00 and $29.00 per month from their current levels of $17.00 and $23.00 respectively. These basic charges are still considerably below the embedded customer-related costs of approximately $37 and $54. Similar to Schedule 7, this approach balances the Bonbright principles of reflecting costs and sending the appropriate price signals for conservation. As with Schedule 7, we capture the difference between the allocated costs and the various revenues within the Distribution Charge.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh on a declining basis to 13 mills per kWh (prior to adding the System Usage Charge) in order to provide a transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. The design provides effective rate migration for customers who migrate from volumetric-based distribution pricing to demand-based distribution pricing (Schedule 32 to 83). Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise fees and Trojan Decommissioning.

We set the **Energy Charge** on a flat year-round basis that is based on the allocation of generation costs.

Q. Do you incorporate a projection of the revenue impacts of the voluntary portfolio TOU option in the calculation of the energy price?

A. Yes. We estimate that by continuing to price the voluntary TOU customers in a manner that presumes their load shape is the same as the overall rate schedule, PGE will incur a revenue shortfall of approximately $61,000. We incorporate this impact in the standard Schedule 32 energy charge.

Q. Briefly describe Schedule 532.

A. Schedule 532 sets out the charges associated with PGE's distribution services. Energy supply and transmission costs are excluded because the customer's Electricity Service Supplier (ESS) provides these services.

Schedule 532 includes the same Basic and Distribution Charges as Schedule 32, with one exception, a distribution price reduction associated with franchise fees discussed earlier in testimony. This distribution price reduction is also applicable to Schedules 538, 549, 491/591, 492/592, and 495/595. We incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater than 30 kW and less than or equal to 200 kW. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these prices. The Schedule 83 charges include more detail because Large Nonresidential customers are generally more sophisticated energy users and are presumably more able to react to pricing signals triggered by their peak consumption. Schedule 83 is for secondary delivery voltage only. The proposed prices are listed below:

Table 4
Schedule 83 - General Service 31-200 kW

Category	Monthly Price	
Basic Charge Single Phase	$35.00	per customer per month
Basic charge Three Phase	$45.00	per customer per month
Trans & Related Services	$0.79	per on-peak kW
Facility Capacity Charge (First 30 kW)	$3.60	per kW Facility capacity
Facility Capacity Charge (Over 30kW)	$3.50	per kW Facility Capacity
Distribution Demand Charge	$2.66	per on-peak kW
COS Energy Charge On-peak	65.47	mills per kWh
COS Energy Charge Off-peak	50.47	mills per kWh
System Usage Charge	7.78	mills per kWh

Q. Please describe how you develop the Schedule 83 prices.

A. We propose to maintain the current Schedule 83 single-phase **Basic Charge** of $35.00 and the three-phase charge of $45.00. This pricing level helps enable a smooth transition for Schedule 32 customers whose demand exceeds 30 kW and move to Schedule 83. Similar to Schedule 32, these basic charges are set considerably below the embedded customer-related costs. The System Usage Charge recovers the remaining customer-related costs as well as any other costs either not fully recovered or more than fully recovered through the appropriate charge.

For Schedules 83, we set the **Transmission & Related Service Charge** to $0.79 per kW of on-peak demand consistent with the other secondary voltage customers served on Schedules 85 or 89. We do this to make the pricing more consistent for customers who choose Direct Access Service under Schedules 583, 485/585, 489/589, or 490/590. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently we flow the over-recovery through to the System Usage Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. We recover the costs associated with 13 kV facilities through the Facility Capacity Charge. We set the Facility Capacity Charge for the first 30 kW minimally higher than the Facility Capacity Charge for over 30 kW to once again provide a smooth transition for Schedule 32 customers who migrate to Schedule 83 because their Demand exceeds 30 kW. This declining block structure also reflects the declining unit cost nature of the distribution system.

We set the **Demand Charge,** which recovers distribution substations and 115 kV costs where applicable, at $2.66 per kW of on-peak demand by combining the demand-related costs and billing determinants for Schedules 83, 85, 89, and 90 such that these schedules will have the same secondary voltage and primary voltage demand charges. Any over- or under-collections of these demand-related costs are captured through other charges applicable to the specific schedules.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge.** This charge recovers franchise fees and Trojan Decommissioning costs, as well as any other costs not fully recovered by the other charges. Again, the System Usage Charge is lower for Schedule 583 than for Schedule 83 because Schedule 583 customers are not charged for generation and transmission by PGE.

We calculate the COS Energy Charges based on the results of the generation allocations, maintaining the current on-and off-peak differential at 15 mills per kWh.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from PGE's market-based energy option. The market-based option available to Schedule 83 is daily pricing based on the prices for the Mid-Columbia (Mid-C) hub as reported by the Intercontinental Exchange Daily On- and Off-Peak Firm Pricing Index (ICE Mid-C Firm Index). Customers may also choose to receive service from an ESS, the details of which are discussed below.

Customers receiving service from an ESS or from a PGE market option receive the Schedule 128, Short-Term Transition Adjustment.

Q. What schedule is applicable to Schedule 83 customers who wish to elect the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a PGE-supplied energy price, nor a Transmission & Related Services Charge. In addition, consistent with the franchise fee discussion above, the System Usage prices for Schedule 583 are lower than those for Schedule 83. This is also true for Schedules 485/585, 489/589, and 490/590 relative to their COS equivalent schedules.

Q. Please provide the proposed monthly prices for Schedule 85 and describe the customers to whom these prices apply.

A. Schedule 85 applies to all Large Nonresidential customers whose Facility Capacity demands are between 201 kW and 4,000 kW. Those customers whose facility capacity exceeds 4,000 kW take service under Schedule 89, which we discuss below. We base the individual charges on the results of the marginal cost study and subsequent ratespread, paying particular attention to appropriately pricing the cost differentials between secondary and primary delivery voltages. The prices differentiated by delivery voltage are in Table 5 below:

Table 5
Schedule 85 General Service 201-4,000 kW

Category	Secondary Prices	Primary Prices
Basic Charge	$590.00 per customer per month	$490.00 per customer per month
Trans & Related Services	$0.79 per on-peak kW	$0.77 per on-peak kW
Facility Capacity Charge (First 200 kW)	$3.27 per kW Facility Capacity	$3.20 per kW Facility Capacity
Facility Capacity Charge (Over 200 kW)	$2.07 per kW Facility Capacity	$2.00 per kw Facility Capacity
Distribution Demand Charge	$2.66 per on-peak kW	$2.58 per on peak kW
COS Energy Charge On-peak	63.58 mills per kWh	62.50 mills per kWh
COS Energy Charge Off-peak	48.58 mills per kWh	47.50 mills per kWh
System Usage Charge	1.18 mills per kWh	1.14 mills per kWh

Q. Please describe how you develop the Schedule 85 prices.

A. The Schedule 85 **Basic Charges** differ by delivery voltage. For secondary service and primary voltage, we set the monthly Basic Charges at $590 and $490, respectively. These Basic Charges, subject to rounding, recover the full amount of the allocated customer-related costs with the exception of the marginal costs of transformer and service drops for secondary voltage customers, which are recovered through the facility capacity charges. Recovery of these costs through the facility capacity charges provides a differential between primary and secondary facility capacity charges similar to that stipulated to in UE 319. These customer charges combined with the declining block facilities charges also help transition those Schedule 83 customers whose demand grows to exceed 200 kW.

For Schedules 83, 85, 89 and 90, we set the **Transmission & Related Service Charge** to $0.79 per kW of on-peak demand for secondary service, and to $0.77 per kW for primary service, prices that are similar to the Schedule 85 allocated revenue requirements.

The **Distribution Charges** for Schedule 85 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with 13 kV facilities through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflects the difference in estimated peak demand losses for the respective delivery voltages. The Facilities Capacity Charge also recovers any over- or under-recovery of the other charges.

The **Demand Charges** of $2.66 and $2.58 for secondary and primary voltage customers, respectively, are set in conjunction with the demand charges for Schedules 83, 89, and 90 as discussed earlier. We calculate the demand charge difference based on the difference in peak demand losses of the respective delivery voltages.

Because several energy options are available to Schedules 85 and 585, we separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, and the CIO. We also use this charge for Schedules 83, 85, 89, and 90 to capture the Schedule 129 transition adjustment revenues and the generation fixed cost contribution true-ups of either returning or departing long-term direct access customers. The System Usage Charge is lower for both Schedules 485 and 585 for the reasons stated earlier in testimony.

We calculate the COS energy charges based on the results of the generation allocations. We maintain the current on- and off-peak differential of 15 mills/kWh. We calculate the energy price difference between the secondary and primary voltage customers based on the difference in embedded line losses.

Q. Please describe the Schedule 85 Energy Charge options.

A. The Schedule 85 energy price options are the same as those for Schedule 83 described above with the exception that qualifying customers may choose long-term direct access through Schedule 485. Schedule 85 customers may also choose the annual direct access option through Schedule 585.

Q. Please provide the proposed monthly prices for Schedule 89 and describe the customers to whom these prices are applicable.

A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW. The Schedule 89 prices, differentiated by delivery voltage, are in Table 6 below:

Table 6
Schedule 89 General Service Greater than 4,000 kW

Category	Secondary Prices	Primary Prices	Subtransmission Prices
Basic charge	$3,540.00 per month	$2,040.00 per month	$4,190.00 per month
Transmission & Related Charge	$ 0.79 per on peak kW	$0.77 per on peak kW	$0.76 per on peak kW
Facility Capacity Charge First 4,000 kW	$1.52 per kW Facility Capacity	$1.48 per kW Facility Capacity	$1.48 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.21 per kW Facility Capacity	$1.17 per kW Facility Capacity	$1.17 per kW Facility Capacity
Distribution Demand Charges	$2.66 per on-peak kW	$2.58 per on-peak kW	$1.29 per on-peak kW
COS Energy Charge On-peak	61.07 mills per kWh	60.07 mills per kWh	59.32 mills per kWh
COS Energy Charge Off-peak	46.07 mills per kWh	45.07 mills per kWh	44.32 mills per kWh
System Usage Charge	1.26 mills per kWh	1.22 mills per kW	1.20 mills per kWh

Q. Please describe how you develop the Schedule 89 Charges.

A. We set the **Basic Charges** for secondary, primary and subtransmission voltage customers at 100% of the customer-related costs for each delivery voltage.

The **Transmission and Related Service Charge** is calculated in conjunction with Schedules 83, 85, and 90 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facility Capacity Charge recovers the remainder.

As specified above, we calculate the **Distribution Demand Charge** in conjunction with Schedules 83, 85, and 90. Any under-collection of costs is recovered through the Facility Capacity Charge. For both secondary and primary voltage customers, the Distribution Demand Charge reflects the marginal cost of providing substations and shared subtransmission facilities, subject to the conjunctive pricing with other schedules referenced above. For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the costs of the shared subtransmission system, again subject to the conjunctive pricing with other rate schedules. It also reflects the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of four cents/kW is subtracted from the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery. As with Schedule 85, we set the delivery voltage price differentials based on the peak demand loss differences of the respective delivery voltages.

The **Facility Capacity Charge** for Schedule 89 customers has two blocks; one for the first 4,000 kW, and the second for billing kW greater than 4,000 kW. We set the first block charge 31 cents/kW higher than the second block to reflect the estimated applicable difference in unit costs between different feeder wire gauges and their load carrying capabilities. The Facility Capacity Charges reflect the peak demand loss difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated by delivery voltage. We maintain the current differential of 15 mills/kWh, the same differential as for Schedules 83 and 85. A Daily Price option is also available similar to that described for Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take service under Schedule 589. As with Schedules 83/583 and 85/485/585, Schedules 89 and 489/589 separately identify the System Usage Charge, which is lower for direct access customers.

Q. Please provide the proposed monthly prices for Schedule 90 and describe the customers to whom these prices are applicable.

A. Schedule 90 applies to Large Nonresidential customers whose Facility Capacity exceeds 4,000 kW and whose aggregated load exceeds 100 MWa. All four of the accounts on Schedule 90 are served at primary delivery voltage; the prices are listed in Table 7 below:

Table 7
Schedule 90 General Service Greater than 4,000 kW aggregating to 100 MWa

Category	Primary Voltage Prices
Basic Charge	$6,600.00 per month
Transmission & Related Charge	$0.77 per on-peak kW
Facility Capacity Charge First 4,000 kW	$1.59 per kW Facility Capacity
Facility Capacity Charge Over 4,000 kW	$1.28 per kW Facility Capacity
Distribution Demand Charge	$2.58 per on-peak kW
COS Energy Charge On-peak	58.49 mills per kWh
COS Energy Charge Off-peak	43.49 mills per kWh
System Usage Charge	0.78 mills per kWh

Q. Please describe how you develop the Schedule 90 Charges.

A. We set the **Basic Charge** at 100% of customer-related costs consistent with how we price Schedules 85 and 89. In prior dockets, we set the Basic Charge at a level exceeding cost, but, because of the redistribution of certain allocated costs between Schedules 89 and 90, we set the Schedule 90 Basic Charge at cost.

Similar to Schedule 89, we calculate the **Transmission and Related Service Charge** in conjunction with Schedules 83, 85, and 89. Also, similar to Schedule 89, because this charge is less than the allocated costs, we use the Facility Capacity Charge to recover the remainder.

The **Distribution Demand Charge** of $2.58 per kW of on-peak demand is also calculated in conjunction with Schedules 83, 85, and 89.

We block the **Facility Capacity Charge** with the same price differential as Schedule 89 and flow through any over- or under-recovery of costs through this charge.

The **COS Energy Charge** is differentiated by on- and off-peak hours with a 15 mills/kWh differential. There is also a Daily Price Option and Direct Access options similar to those for Schedules 85 and 89.

Q. Please discuss how you priced Schedules 38, 47 and 49.

A. **Schedule 38, Large Nonresidential Optional Time-of-Day Standard Service** is, as its name implies, an optional schedule that is applicable to customers whose facility capacity is between 31 and 200 kW. We propose to increase the monthly Basic Charge to $30 for single- and three-phase service customers. We maintain the volumetric recovery of transmission and distribution costs and continue to differentiate the energy charges based on the on- and off-peak periods defined in Schedule 38. We increase the differential on- and off-peak hours from 10 to 15 mills/kWh. Schedule 38 customers may take Direct Access Service under Schedule 538.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose demand does not exceed 30 kW. We propose to increase the Basic Charge to $37.00 per month, applicable during the months of May through October. We maintain the blocked volumetric distribution charges for these schedules as well as the volumetric recovery of transmission and generation costs. The direct access equivalent schedule for Schedule 47 is Schedule 532.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We propose to increase the Basic Charge to $45. Schedule 49 customers may take Direct Access Service under Schedule 549.

Q. Please describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules provide service to lighting and traffic signal customers and are discussed below:

We structure **Schedule 15, Outdoor Area Lighting Standard Service** charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges.

Schedules 91/491/591 and 95/495/595, Street and Highway Lighting Standard Service, provide municipalities with outdoor lighting service. These schedules are similar in structure to Schedule 15. Each service-option monthly rate includes the applicable unbundled costs, based on the monthly kWh usage of the particular type of light. A summary of the proposed pole and luminaire prices for the lighting schedules is provided in PGE Exhibit 1305.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access-related energy-only based charge for this specialty service. Schedules 92/592 remain grandfathered services closed to additional governmental agencies.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. We propose no price impact mitigation for the purpose of limiting the amount of increase to some rate schedules. As specified earlier, we use the CIO to equalize the distribution prices for the outdoor lighting schedules because of the similar nature of the services provided. In addition, we follow the UE 319 stipulation regarding EE allocations and provide a reallocation from Schedules 89/489/589 of $618,652, and 90/490/590 of $154,663, that apply to Schedules 7 and 32.

Q. How do you implement the CIO?

A. We increase the System usage Charges for Schedule 89/489/589 and 90/490/590 and reduce the distribution charges for Schedules 7 and 32. For Schedule 15, we increase the distribution charge while reducing the distribution charges for Schedules 91 and 95.

V. Other Rate Schedule Changes

A. Decoupling

Q. Please describe PGE's Schedule 123 Decoupling Mechanism.

A. For Schedules 7 and 32, the Sales Normalization Adjustment (SNA) compares actual weather-adjusted distribution, transmission, and fixed generation revenues that are collected on a volumetric basis with those that would be collected with a fixed per-customer charge. The difference is accumulated in a balancing account and refunded or collected over a future period.

The Lost Revenue Recovery Adjustment (LRRA) component of Schedule 123 is a limited revenue recovery mechanism tied to the reduced kWh sales resulting from incremental EE savings generated through ETO programs directed to nonresidential customers other than Schedule 32. The LRRA applies to PGE nonresidential customers other than Schedule 32 whose load does not exceed one average megawatt at a Point of Delivery during the prior calendar year and those nonresidential customers who qualify as a Self-Directing Customer.

To mitigate customer impacts, a 2% annual limiter applies to Schedule 123 rate revisions that result in a rate increase to the applicable SNA or LRRA rate schedule. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

Q. What structural changes in Schedule 123 Decoupling do you propose for 2019?

A. We propose the following modifications to Schedule 123:

- Discontinue the LRRA;
- Apply the SNA to Schedules 38/538, 47, and 49/549, and to the fixed generation portion of the volumetric generation charges in Schedules 83 and 85;

- Remove the weather adjustment from the SNA to allow the full differences in use per customer to be refunded to customers or charged to customers; and
- Keep the 2% limiter, but include the ability to balance any amounts over 2% to the subsequent year or years.

Q. Why do you propose to eliminate the LRRA and replace it with a revenue-per-customer form of decoupling for Schedules 38/538, 47, 49/549, 83, and 85?

A. We propose this in order to explore the ramifications of revenue-per-customer decoupling for large nonresidential customers. Electric and gas utilities in Washington have recently adopted revenue-per-customer forms of decoupling for larger commercial customers.[2] In addition, gas companies in Oregon either currently employ or have proposed to employ decoupling for larger commercial customers.[3] Implementing a revenue-per-customer form of decoupling for Schedules 38/538, 47, 49/549, 83, and 85 allows PGE to more closely align with what appears to be a regional trend.

Furthermore, by eliminating the LRRA, we will no longer be dependent upon the Annual Reports provided by the ETO for calculation of a portion of Schedule 123. In past years, the ETO provided the allocation of Senate Bill (SB) 1149 and SB 838 EE savings late in the year, necessitating PGE to request a filing date of November 1 for amortizing prior year results.

Q. Does eventually eliminating the LRRA mean that PGE could implement the decoupling results more rapidly than it currently does?

[2] See tariffs for Avista (OR) – Schedule 175 (Natural Gas); Avista (WA) – Schedule 75 (Electric); Cascade Natural Gas (WA) – Rule 21; and Puget Sound Energy (WA) – Schedule 142 (Electric & Natural Gas).

[3] See tariff for Avista (OR) – Schedule 475; and Docket No. UG 344 – NW Natural/900.

A. Yes. Although we are not proposing changes to the time and manner of filing for Schedule 123 at this time, we are open to eventually changing the timing of amortization. Conceivably, without the LRRA, PGE could implement the decoupling results as early as May of the following year, if necessary.

Q. Why do you propose to eliminate the weather adjustment from the SNA?

A. We propose eliminating the weather adjustment because it burdens customers and PGE with increased weather risk. For example, adjusting consumption for weather variability above normal weather conditions can result in over-recovery of fixed costs at the expense of customers. Conversely, adjusting for weather variability below normal weather conditions can result in under-recovery of fixed costs to the benefit of customers. By eliminating weather normalization from the SNA calculation, the decoupling mechanism will allow the full differences in use per customer to be refunded to customers or charged to customers, thus avoiding over- and under-recovery scenarios, and provides a reduction in weather risk.[4]

Q. Hypothetically, how would eliminating the weather adjustment from the SNA have affected the Schedule 123 results for 2017?

A. Eliminating the weather adjustment from the SNA calculation would have a significant impact on 2017 results that will be amortized in 2019. For Schedule 7, rather than the approximately $15 million charge residential customers will pay, they would have received a refund of about $10 million by removing the weather adjustment. Residential customers would have benefited by $25 million.

Schedule 32 would also have benefited if the weather adjustment were removed, based on 2017 results, but by a more modest amount. A summary comparing the SNA portion of

[4] See PGE Exhibit 1306, Section 4.5 for further discussion of weather effects and the SNA.

Schedule 123 with and without the weather adjustment for both Schedule 7 and Schedule 32 is presented in PGE Exhibit 1307.

Q. Why do you propose changes to the 2% limiter?

A. The current 2% rate increase cap acts as a “circuit breaker” to minimize the risk that rate revisions to the SNA or LRRA mechanisms result in bill impacts greater than 2% in any particular year. However, there is no limiter applied to SNA revisions that result in a rate decrease. We propose to continue the 2% limit for customer protection, but allow amounts in the balancing account that exceed the 2% limit to carry forward to the subsequent year (or years) for recovery.

Q. What changes in Schedule 123 prices do you presume for 2019?

A. For the SNA portion of Schedule 123, we provide a preliminary estimate of the Schedule 123 prices that include activity through the January 2018 billing cycle. For Schedule 7, the anticipated charge in Schedule 123 will result in an increase in revenues from the current Schedule 123 charge designed to collect approximately $0.7 million from Schedule 7 customers during 2018 (based on 2016 results). We estimate a collection of approximately $15 million in 2019 (based on 2017 results).

For Schedule 32, we anticipate a slightly greater credit than the current prices designed to refund $1.1 million. We presume that the LRRA portion of Schedule 123 will be at the same level as current. The estimated change in Schedule 123 prices results in a decrease in revenues. This filing doesn’t include the impact of the increase. However, the Schedule 123 overall increase is likely to be offset by the refund included in the 2018 income tax adjustment in Schedule 132 discussed later.

B. Schedule 132 Tax Adjustment

Q. What is the purpose of Schedule 132 Tax Adjustment?

A. The purpose of Schedule 132 is to refund to customers the difference in revenues due to the U.S. Tax Reconciliation Act, applicable primarily to the 2018 tax year. PGE filed a deferral docketed as UM 1920 to capture the revenue requirement effects. Although the benefits are not quantified in this filing, the schedule is introduced.

C. Schedule 122

Q. What 2019 changes do you propose for Schedules 122?

A. Schedule 122 is PGE's renewable energy resources automatic adjustment clause. We propose to include energy storage in addition to renewable resources. SB 1547 directs the Commission to establish an automatic adjustment clause as defined in ORS 757.210 or another method to allow timely recovery of prudently incurred costs for the utility to construct or acquire renewable resources, associated transmission, and associated energy storage. PGE's resources are system resources. Any energy storage facility on the system controlled by PGE provides integrating renewable energy resources as a primary system benefit.

D. Schedule 102

Q. What 2019 changes do you propose for Schedules 102?

A. We propose to adjust the blocked prices associated with the Regional Power Act Exchange Credit for residential customers. Currently, the credit is only provided to customers for the first 1,000 kWh. We intend to provide the same credit to all energy usage. However, to minimize bill impacts to customer with monthly energy use of 1,000 kWh or less, we propose to provide about half of the credit for usage over 1,000 kWh.

E. Schedule 300

Q. Please describe PGE's Schedule 300.

A. Schedule 300 – Charges as Defined by the Rules and Regulations and Miscellaneous Charges – is a schedule designed to directly assign and charge costs to customers who request services that are not generally within the normal operations of PGE's business. Some examples may include: reconnection or disconnection (for a reason other than safety), temporary electrical service, or the rental of equipment such as transformers. When these services are requested, the costs are assigned directly to the requesting customer. This direct application of cost-causation is consistent with Bonbright's principles of rate design, listed on page 12 of this testimony.

Q. Is PGE requesting any methodology changes regarding how Schedule 300 charges are calculated or applied?

A. Yes. PGE is requesting that temporary area light service be priced at estimated actual cost, rather than per luminaire. Other than temporary area lights, PGE's requested changes to Schedule 300 retain the same methodology that has been used historically to price miscellaneous services offered by PGE. The Schedule 300 prices are cost-based, and modifications requested in this docket represent the change in costs from the last update of Schedule 300 – in 2011 – to present.

Q. Please explain PGE's decision to change the pricing method of temporary area lights to estimated actual cost.

A. Temporary area lighting is a service that can be highly variable in both quantity of lights requested and the amount of time that the lights are needed. This, combined with the vast variety of luminaires that could be requested by a customer (PGE currently has approximately 70 luminaire options available for customers to request) necessitates the flexibility for PGE to tailor the cost of temporary lighting to the customer's need.

Q. Does PGE currently have any temporary area light customers?

A. No.

Q. Is PGE proposing to remove any services from Schedule 300?

A. Yes. PGE is proposing to remove Meter Installation Rates (Rule M) and Meter Rental Rates (Rule M) from Schedule 300. Meter rentals are not part of PGE's current business, no rentals have been requested in the past 3 years, and no customers are currently renting meters. Any installation or reading charges associated with a non-network meter should be captured under "Non-network Residential Meter Rates (Rule M)."

With regard to meter installation rates, PGE requests that those be removed from Schedule 300, as meter installation is part of PGE's base business.

Q. Please describe the other changes to Schedule 300 that PGE is requesting.

A. PGE is requesting Schedule 300 price changes as follows:

- Customer Requested Disconnection and Reconnection Rates (Rule H) – The Reconnect Standard Rates are updated to show pricing at estimated actual cost. Additionally, the After Hours prices have been eliminated, as the actual cost to reconnect does not vary with time of day. The calculations underlying this change are shown in the confidential work paper provided with this filing.
- Service of Limited Duration (Rule L) – rates for Standard Temporary Service and Enhanced Temporary Service have been updated to show current estimated actual costs. The calculations underlying this change are shown in the confidential work paper provided with this filing.

- Non-Network Residential Meter Rates (Rule M) – The monthly charge for non-network meter reads and the one-time charge for the installation of a non-network meter have been updated to reflect current costs.
- Transformers (Rule I, Section 3) – the rental cost of Submersible Transformers in subdivisions, mobile homes, and multi-family units has been updated to show current actual costs.

F. Long-Term Cost of Service Opt-Out for Large Nonresidential Customers

Q. What is the long-term opt-out program?

A. The long-term opt-out program is often referred to as the five-year opt out due to the current provision for five years of transition adjustments. The customer opts out of COS for energy supply and chooses an alternative energy supply. After five years of transition adjustments (described in more detail below), transition adjustments are no longer applicable. However, the customer remains a non-COS customer and must provide three-year notice, or two-year notice for earlier enrollment periods, to return to COS.

Q. Please summarize PGE's direct access offerings since direct access was originally authorized by SB 1149 in 1999.

A. PGE began offering a one-year direct access/market price option effective March 1, 2002, consistent with the provisions of SB 1149 (Chapter 865, Oregon Laws 1999) and House Bill 3633 (Chapter 819, Oregon Laws 2001). Beginning with the 2003 service year, PGE added the option for eligible customers to opt out of COS energy supply for a minimum five-year period with a pre-specified transition adjustment. Eligibility for this option was and continues to be an enrollment of at least one MWa with each Point of Delivery (PODID) having a Facility Capacity of at least 250 kW. This eligibility requirement was put into place to limit the number of accounts that must be separately tracked, thereby helping to mitigate the administrative burden to PGE. This option allowed customers to opt out of COS with the option to return to COS, with a two-year notice. Commencing with the 2005 service period, PGE added a three-year COS opt-out provision, again with a pre-specified transition adjustment, but with an automatic return to COS pricing after the three-year period. Commencing with the 2008 service year, we added quarterly balance-of-year direct access windows and a new split-load schedule that allowed very large customers to receive direct access service for a percentage of their usage, with the remainder served by PGE at COS prices. In a stipulation with various parties in 2012, approved by Commission Order No. 12-057, PGE modified the 2% limiter and eligibility, and changed the calculation of the Schedule 129 transition adjustments to be on the same basis as the Schedule 128 transition adjustments.

Finally, in a stipulation with various parties in 2013 approved by Commission Order No. 13-459, PGE made further modifications and the parties agreed not to make any new proposals for the 2015-2018 service years. Before the moratorium, the modifications to the long-term opt-out program included: setting the variable portion of the transition adjustment in advance of the enrollment period and not updating it during the applicable five-year period; updating annually the fixed generation portion of the Schedule 129 transition adjustments during the five-year transition adjustment period; and requiring customers to provide three year's notice to return to COS. The modifications to the three-year opt out program included fixed Schedule 129 transition adjustments that are: not subject to change; calculated according to an agreed upon methodology; levelized; and differentiated by tariff schedule and delivery voltage. Finally, the stipulation added new schedules to provide direct access for street lighting and traffic signal customers. PGE has now offered a long-term opt-out of COS pricing on sixteen different occasions.

Q. What is the intent of PGE's long-term opt-out program?

A. PGE's long-term opt-out program is intended to allow a customer to fully transition off PGE COS supply while minimizing unwarranted cost shifting[5] to nonparticipating customers.

Q. Did the statute mandate that PGE offer the long-term opt-out option at the time PGE first made it available?

A. No. PGE voluntarily offered this option based on comments received from ESSs and certain customers. Division 38 of the Oregon Administrative Rules (OARs) was subsequently amended in 2004 to require that utilities offer customers a multi-year opt-out option from COS pricing on an annual basis. The rules do not, however, specify the term of the multi-year opt-out.

Q. Regarding the long-term opt-out program, are customers eventually able to permanently avoid PGE's fixed generation revenue requirements?

A. Yes. For the first five years, these customers receive transition adjustments that incorporate the fixed generation revenue requirements from PGE's most recent general rate case, with updates to fixed generation for each of the remaining four years. The transition adjustment may also contain additional fixed generation revenue requirements. An example of the latter is the fixed generation revenue requirements contained in PGE Schedule 145, Boardman Power Plant Operating Life Adjustment. Commencing in year six and thereafter, customers who choose the five-year option pay (or receive) no transition adjustments.

[5] ORS 757.607.

Q. Is PGE required to offer this long-term opt-out of its fixed generation revenue requirements?

A. No. OAR 860-038-0275 (5) specifies only the following: “At least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment.”

Q. What is the purpose of transition adjustments?

A. Transition adjustments attempt to provide remaining COS customers with the cost or benefit of direct access customer choosing to leave COS.

Q. What costs do transition adjustments include?

A. Transition adjustments compare COS prices with expected market prices related to generation. The COS prices include both fixed generation and net variable power costs.

Q. Does PacifiCorp offer a long-term opt-out of fixed generation costs?

A. Yes. However, PacifiCorp includes ten years of fixed generation costs into a five year period.

Q. Does the current mix of direct access options and their impacts on non-participating customers concern you?

A. Yes. The current mix of options provide participating Large Nonresidential customers an opportunity for unwarranted cost shifts to other customers who do not or cannot select a long-term direct access option. Furthermore, this opportunity for participants to shift costs to nonparticipants is currently made available every year.

Q. Please specify the proposed changes to PGE’s direct access offerings.

A. PGE proposes the following changes to its direct access offerings:

- Modify the Schedule 129 transition adjustments to reflect ten years of fixed generation costs over ten years, with annual updates to fixed generation costs to reflect actual costs.
- Add language to PGE's Rule K to allow PGE to petition the Commission to decertify an ESS if they do not follow required scheduling practices**.**

Q. Why do you propose to modify the Schedule 129 transition adjustments to reflect ten years of fixed generation costs over ten years, with annual updates to fixed generation costs to reflect actual costs?

A. Allowing ten years of fixed costs will help protect remaining COS customers from undue cost shifting when large nonresidential customers choose to opt out of COS on a long-term basis. It also more closely aligns PGE's Schedule 129 transition adjustments with PacifiCorp's long-term opt-out program.

Q. Why did the Commission allow PacifiCorp to recover ten years of fixed generation costs in five years of transition adjustments?

A. The Commission stated, in Order No. 15-060:

> "The Stipulating Parties failed to rebut PacifiCorp's evidence of transition costs, up to approximately $60 million, in years six to ten of the program, and rely too heavily on mere assertions about how transition costs beyond year five can be reduced or erased. Moreover, we reject the Stipulating Parties' arguments that PacifiCorp's system load growth will completely mitigate any transition costs. As PacifiCorp notes, GRID considers forecasted system load growth in calculating both the transition adjustments and the consumer opt-out charge."

Q. What is the harm to PGE's customers in years 6-10 related to long-term opt outs?

A. Using a very conservative estimate, with fixed generation not growing from current levels and no growth in loads by the customers opting out, we estimate harm to remaining COS customers of about $76 million. See PGE Exhibit 1308.

Q. Is it likely that PGE's fixed generation will grow over the next few years?

A. Yes. The fixed generation assumption in PGE Exhibit 1308 is very likely to be understated. PGE may issue a renewable resource request for proposal in the near future. With or without load growth, renewable portfolio standards are increasing every five years. In 2025, Oregon's renewable portfolio standards (RPS) increase from 20% to 27% of energy. Further increases in RPS are to 35% in 2030, to 45% in 2035, and to 50% in 2040.

Q. Why do you propose to modify Rule K to allow PGE to petition the Commission to decertify an ESS if they do not follow scheduling practices?

A. PGE does not have a mechanism to enforce reasonable hourly scheduling by each ESS. PGE's experience is that some ESSs will schedule energy on a fairly flat basis over a month, largely disregarding the hourly shape of the energy used by its customers.

Q. Are ESSs scheduling accurately?

A. While ESSs are subject to penalty charges, some are scheduling with reasonable accuracy and some are not. Table 8 below provides a list using a generic ESS name and shows the percentage of hours with hourly deviation greater than 20% of the scheduled amount for each month. The months shown are November through December 2017. We chose those months because PGE began participating in the Western EIM in October of 2017. September is excluded since it was the first month of PGE's Western EIM participation.

Table 8
Percent of Hourly Deviations Greater than 20%

	Dec-17	Nov-17	Oct-17
ESS-1	11.4%	5.5%	6.9%
ESS-2	1.5%	0.1%	12.9%
ESS-3	30.5%	0.0%	0.9%
ESS-4	33.3%	19.2%	38.4%
ESS-5	N/A	N/A	N/A

Q. What are the current mechanisms to encourage accurate scheduling by an ESS and why have those not worked?

A. The Division 38 rules direct the ESS to schedule in accordance with all generally accepted regional and Western Electricity Coordinating Council (WECC) rules and guidelines. They must also have the necessary transmission and settle imbalances. The current mechanism has not worked because some ESSs, in the face of imbalance charges, continue to schedule energy on a relatively flat basis in large increments.

Q. What are the impacts of poor scheduling by an ESS?

A. When a customer chooses direct access, they choose to no longer have generation and transmission as a COS customer. If the schedule provided by the ESS does not account for the hourly variations of the customer, then PGE's COS customers may be harmed by covering the costs of providing the energy to make sure the direct access customers are served. PGE must fill in the gaps left by the ESS. In addition, poor scheduling may affect PGE's reliability. PGE is ultimately responsible to serve all customers, including direct access customers. If PGE faces a system or regional emergency such as when a plant goes offline, PGE must find the energy to fill the gap. PGE needs each ESS to schedule accurately so that they are covering the energy needs of direct access customers. In the case of a regional emergency, the market may not have energy available, and poor ESS scheduling will make an already bad situation worse.

Q. What do you propose to encourage ESSs to provide reasonable schedules of energy?

A. We propose to modify PGE's Rule K to allow PGE to ask the Commission to decertify an ESS if the ESS has excessive imbalances. ESSs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month would receive notification from PGE of the poor scheduling practice. A second occurrence within 12 months would result in PGE requesting the Commission decertify the ESS.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1301	Proposed Tariff Changes
1302	Estimated Impact of Proposed Changes on Customers
1303	Rate Design
1304	Allocation of Costs to Customer Classes
1305	Streetlight and Area Lights
1306	Decoupling Evaluation
1307	Decoupling Hypothetical for 2017
1308	Long-Term Opt Out Impacts Years 6-10

Advice No. 18-02
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 15, 2018

Twelfth Revision of Sheet No. 7-1
Tenth Revision of Sheet No. 15-1
Eleventh Revision of Sheet No. 15-2
Twelfth Revision of Sheet No. 15-3
Thirteenth Revision of Sheet No. 15-4
Eighth Revision of Sheet No. 15-5
Sixth Revision of Sheet No. 15-6
Eleventh Revision of Sheet No. 32-1
Eleventh Revision of Sheet No. 38-1
Eleventh Revision of Sheet No. 47-1
Twelfth Revision of Sheet No. 49-1
Fourteenth Revision of Sheet No. 75-1
Twelfth Revision of Sheet No. 76R-1
Thirteenth Revision of Sheet No. 83-1
Tenth Revision of Sheet No. 85-1
Fourteenth Revision of Sheet No. 89-1
Sixth Revision of Sheet No. 90-1
Fourteenth Revision of Sheet No. 91-7
Eleventh Revision of Sheet No. 91-9
Tenth Revision of Sheet No. 91-10
Tenth Revision of Sheet No. 91-11
Tenth Revision of Sheet No. 91-12
Ninth Revision of Sheet No. 91-13
Eighth Revision of Sheet No. 91-14
Tenth Revision of Sheet No. 91-15
Thirteenth Revision of Sheet No. 92-1
Eighth Revision of Sheet No. 95-3
Thirteenth Revision of Sheet No. 95-5
Sixth Revision of Sheet No. 95-8
Eleventh Revision of Sheet No. 102-1
Fourteenth Revision of Sheet No. 122-1
Fourteenth Revision of Sheet No. 122-2
Third Revision of Sheet No. 122-3
Tenth Revision of Sheet No. 123-1
Ninth Revision of Sheet No. 123-2
Thirteenth Revision of Sheet No. 123-3
Thirteenth Revision of Sheet No. 123-4
Twelfth Revision of Sheet No. 123-5
Third Revision of Sheet No. 123-6
Original Sheet No. 123-7
Thirteenth Revision of Sheet No. 125-2
Tenth Revision of Sheet No. 126-1
Ninth Revision of Sheet No. 126-3
Twenty Second Revision of Sheet No. 128-1
Twenty First Revision of Sheet No. 128-2
Nineteenth Revision of Sheet No. 129-2
Thirtieth Revision of Sheet No. 129-3
Fourth Revision of Sheet No. 129-6
Seventeenth Revision of Sheet No. 300-1
Third Revision of Sheet No. 300-2
Third Revision of Sheet No. 300-3
Fourth Revision of Sheet No. 300-4
Fifth Revision of Sheet No. 300-5
Fifth Revision of Sheet No. 300-6
First Revision of Sheet No. 310-1
Ninth Revision of Sheet No. 485-1
Fourteenth Revision of Sheet No. 489-1
Sixth Revision of Sheet No. 490-1
Sixth Revision of Sheet No. 491-6
Tenth Revision of Sheet No. 491-8
Eighth Revision of Sheet No. 491-9
Eighth Revision of Sheet No. 491-10
Eighth Revision of Sheet No. 491-11
Seventh Revision of Sheet No. 491-12
Seventh Revision of Sheet No. 491-13
Sixth Revision of Sheet No. 491-14
Sixth Revision of Sheet No. 492-1
Sixth Revision of Sheet No. 495-3
Ninth Revision of Sheet No. 495-5
Eighth Revision of Sheet No. 495-8
Eleventh Revision of Sheet No. 515-1
Twelfth Revision of Sheet No. 515-2
Eleventh Revision of Sheet No. 515-3
Eighth Revision of Sheet No. 515-4
Tenth Revision of Sheet No. 532-1
Eleventh Revision of Sheet No. 538-1
Eleventh Revision of Sheet No. 549-1
Fourteenth Revision of Sheet No. 575-1
Twelfth Revision of Sheet No. 576R-1
Twelfth Revision of Sheet No. 583-1
Ninth Revision of Sheet No. 585-1
Fourteenth Revision of Sheet No. 589-1
Sixth Revision of Sheet No. 590-1
Sixteenth Revision of Sheet No. 591-6
Twentieth Revision of Sheet No. 591-7
Fourteenth Revision of Sheet No. 591-8
Thirteenth Revision of Sheet No. 591-9
Thirteenth Revision of Sheet No. 591-10
Eleventh Revision of Sheet No. 591-11
Tenth Revision of Sheet No. 591-12
Eleventh Revision of Sheet No. 591-13
Eleventh Revision of Sheet No. 592-1
Thirteenth Revision of Sheet No. 595-3
Ninth Revision of Sheet No. 595-6
Fifth Revision of Sheet No. 750-1
Fifth Revision of Sheet No. 750-2
Fourth Revision of Sheet No. 750-3

PGE hereby withdraws the following Sheet:
First Revision of Sheet No. 300-7

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge Standard Service and Time-of-Use Portfolio	$13.00		(I)
Transmission and Related Services Charge	0.252	¢ per kWh	(I)
Distribution Charge	4.688	¢ per kWh	(I)
Energy Charge Standard Service			
First 1,000 kWh	6.629	¢ per kWh	(I)
Over 1,000 kWh	7.351	¢ per kWh	(I)
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
Transmission and Related Services Charge TOU Portfolio			(I)
On-Peak Period	0.412	¢ per kWh	
Mid-Peak Period	0.412	¢ per kWh	
Off-Peak Period	0.000	¢ per kWh	
Distribution Charge TOU Portfolio			
On-Peak Period	7.657	¢ per kWh	
Mid-Peak Period	7.657	¢ per kWh	
Off-Peak Period	0.000	¢ per kWh	(I)
Energy Charge TOU Portfolio			
On-Peak Period	12.908	¢ per kWh	(I)
Mid-Peak Period	7.351	¢ per kWh	(I)
Off-Peak Period	4.304	¢ per kWh	(I)
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.155	¢ per kWh	(I)
Distribution Charge	6.475	¢ per kWh	(I)
Cost of Service Energy Charge	5.177	¢ per kWh	(I)

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate (1) Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 12.52 (2)	(R)
	400	21,000	147	22.63 (2)	(R)
	1,000	55,000	374	49.66 (2)	(I)
HPS	70	6,300	30	8.31 (2)	(R)
	100	9,500	43	9.85	
	150	16,000	62	12.20	
	200	22,000	79	14.59	
	250	29,000	102	17.18	
	310	37,000	124	20.14	(R)
	400	50,000	163	24.46	(I)
Flood, HPS	100	9,500	43	9.74 (2)	(R)
	200	22,000	79	14.80 (2)	
	250	29,000	102	17.47	(R)
	400	50,000	163	24.68	
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	9.62	(R)
	100	9,500	43	10.85	
	150	16,500	62	13.41	
Special Acorn Type, HPS	100	9,500	43	13.10	
HADCO Victorian, HPS	150	16,500	62	15.34	
	200	22,000	79	18.01	
	250	29,000	102	20.72	
Early American Post-Top, HPS Black	100	9,500	43	10.23	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	$ 12.38	(R)
	175	12,000	71	13.75	
Flood, Metal Halide	350	30,000	139	21.86	
	400	40,000	156	24.05	(R)
Flood, HPS	750	105,000	285	42.28	(I)
HADCO Independence, HPS	100	9,500	43	13.25	(R)
	150	16,000	62	15.49	
HADCO Capitol Acorn, HPS	100	9,500	43	16.68	
	150	16,000	62	17.65	
	200	22,000	79	19.68	
	250	29,000	102	22.37	
HADCO Techtra, HPS	100	9,500	43	21.56	
	150	16,000	62	23.58	
	250	29,000	102	28.13	
HADCO Westbrooke, HPS	70	6,300	30	14.09	
	100	9,500	43	15.21	
	150	16,000	62	21.98	
	200	22,000	79	19.64	
	250	29,000	102	22.92	
Holophane Mongoose, HPS	150	16,000	62	15.72	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Acorn					
LED	60	5,488	21	$ 12.89	(R)
	70	4,332	24	14.17	
HADCO LED	70	5,120	24	17.80	
Cobrahead Equivalent					
LED	37	2,530	13	4.73	
	50	3,162	17	5.18	
	52	3,757	18	5.65	
	67	5,050	23	6.28	
	106	7,444	36	8.10	(R)
	134	14,200	46	12.12	(I)
	156	16,300	53	13.46	(R)
	176	18,300	60	15.16	(I)
	201	21,400	69	15.73	
Westbrooke LED (Non-Flare)	36	3,369	12	15.52	
	53	5,079	18	17.51	
	69	6,661	24	17.47	(I)
	85	8,153	29	18.69	(R)
	136	12,687	46	22.29	
	206	18,159	70	24.84	(R)
Westbrooke LED (Flare)	36	3,369	12	15.88	(I)
	53	5,079	18	18.06	(R)
	69	6,661	24	18.91	(R)
	85	8,153	29	20.22	(I)
	136	12,687	46	21.91	(R)
	206	18,159	70	26.12	
CREE XSP LED	25	2,529	9	3.36	
	42	3,819	14	4.04	
	48	4,373	16	4.68	
	56	5,863	19	5.46	
	91	8,747	31	6.88	(R)
Post-Top, American Revolution					
LED	45	3,395	15	8.19	(I)
	72	4,409	25	8.87	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.18	(I)
	40 to 55	6.17	(R)
Wood, Painted for Underground	35 or less	5.18 [2]	(I)
Wood, Curved Laminated	30 or less	6.51 [2]	
Aluminum, Regular	16	6.39	
	25	10.52	
	30	11.31	(I)
	35	12.59	(R)
Aluminum, Fluted Ornamental	14	9.50	(I)
Aluminum Davit	25	10.57	
	30	11.13	
	35	12.28	
	40	16.15	
Aluminum Double Davit	30	15.23	
Aluminum, Fluted Ornamental	16	10.24	
Aluminum, HADCO, Smooth Techtra Ornamental	18	19.69	
Aluminum, HADCO, Fluted Westbrooke	18	19.05	
Aluminum, HADCO, Smooth Westbrooke	18	19.64	
Concrete Ameron Post-Top	25	17.79	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$ 11.00	(I)
Fiberglass, Regular			
Black	20	4.72	
Gray or Bronze	30	7.92	
Black, Gray, or Bronze	35	7.40	
Fiberglass, Anchor Base, Gray or Black	35	12.92	
Fiberglass, Direct Bury with Shroud	18	7.47	(I)

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$20.00		(I)
Three Phase Service	$29.00		(I)
Transmission and Related Services Charge	0.212	¢ per kWh	(I)
Distribution Charge			
First 5,000 kWh	4.545	¢ per kWh	(I)
Over 5,000 kWh	1.516	¢ per kWh	(I)
Energy Charge Options			
Standard Service	6.073	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.786	¢ per kWh	
Mid-Peak Period	6.073	¢ per kWh	
Off-Peak Period	3.598	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$30.00		(I)
Transmission and Related Services Charge	0.174	¢ per kWh	(I)
Distribution Charge	7.549	¢ per kWh	(I)
Energy Charge*			
On-Peak Period	6.297	¢ per kWh	(I)
Off-Peak Period	4.797	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$37.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.218	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	11.555	¢ per kWh	(I)
Over 50 kWh per kW of Demand	9.555	¢ per kWh	(I)
Energy Charge	7.075	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$45.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.219	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand***	8.412	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.412	¢ per kWh	(I)
Energy Charge	7.035	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,540.00	$2,040.00	$4,190.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(I)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.52	$1.48	$1.48	(R)
Over 4,000 kW	$1.21	$1.17	$1.17	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	$1.29	(R)(I)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.126 ¢	0.122 ¢	0.120 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.031	$0.030	$0.030	(I)
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.104	$0.101	$0.050	(I)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$35.00	(I)
Three Phase Service	$45.00	(I)
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.79	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.60	(R)
Over 30 kW	$3.50	
per kW of monthly On-Peak Demand	$2.66	(R)
Energy Charge (per kWh)		
On-Peak Period***	6.547 ¢	(I)
Off-Peak Period***	5.047 ¢	
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.778 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 85
LARGE NONRESIDENTIAL
STANDARD SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$590.00	$490.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.79	0.77	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.27	$3.20	(I,R)
Over 200 kW	$2.07	$2.00	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	(R)
Energy Charge (per kWh)			
On-Peak Period***	6.358 ¢	6.250 ¢	(I)
Off-Peak Period***	4.858 ¢	4.750 ¢	
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.118 ¢	0.114 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,540.00	$2,040.00	$4,190.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.52	$1.48	$1.48	(R)
Over 4,000 kW	$1.21	$1.17	$1.17	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	$1.29	(R)(I)
Energy Charge (per kWh)				
On-Peak Period***	6.107 ¢	6.007 ¢	5.932 ¢	(I)
Off-Peak Period***	4.607 ¢	4.507 ¢	4.432 ¢	(I)
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.126 ¢	0.122 ¢	0.120 ¢	(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.
*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	\$6,600.00	(I)
Transmission and Related Services Charge per kW of monthly On-Peak Demand	\$0.77	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	\$1.59	(I)
Over 4,000 kW	\$1.28	(I)
per kW of monthly on-peak Demand	\$2.58	(R)
Energy Charge (per kWh)		
On-Peak Period***	5.849¢	(I)
Off-Peak Period***	4.349¢	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.078¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 91 (Continued)

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.155 ¢ per kWh	(I)
Distribution Charge	6.475 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.177 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.307¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0685.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price Option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING

High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	70	6,300	30	*	$ 1.29	(I)
	100	9,500	43	*	1.28	
	150	16,000	62	*	1.29	
	200	22,000	79	*	1.32	
	250	29,000	102	*	1.30	
	400	50,000	163	*	1.34	
Cobrahead	70	6,300	30	$ 4.85	1.51	
	100	9,500	43	4.85	1.51	
	150	16,000	62	4.96	1.53	
	200	22,000	79	5.72	1.58	
	250	29,000	102	5.60	1.56	
	400	50,000	163	5.67	1.57	
Flood	250	29,000	102	5.89	1.60	
	400	50,000	163	5.89	1.60	
Early American Post-Top	100	9,500	43	5.22	1.56	
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.16	1.69	
	100	9,500	43	5.85	1.65	
	150	16,000	62	6.16	1.69	(I)

* Not offered.
** Service is only available to Customers with total power door luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze, or Gray	20	$ 4.79	$ 0.15	(I)
Fiberglass, Black or Bronze	30	7.43	0.24	
Fiberglass, Gray	30	8.05	0.26	
Fiberglass, Smooth, Black or Bronze	18	5.04	0.16	
Fiberglass, Regular				
Black, Bronze, or Gray	18	4.21	0.13	
	35	7.50	0.24	(I)

SCHEDULE 91 (Continued)

RATES FOR STANDARD POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B		
Wood, Standard	30 to 35	$ 5.28	$ 0.17	(I)	(I)
Wood, Standard	40 to 55	6.27	0.20	(R)	(R)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$ 8.47	$ 1.95	(I)
HADCO Victorian, HPS	150	16,000	62	8.47	1.95	
	200	22,000	79	9.13	2.04	
	250	29,000	102	9.13	2.04	
HADCO Capitol Acorn, HPS	100	9,500	43	12.06	2.42	
	150	16,000	62	10.79	2.25	
	200	22,000	79	10.80	2.26	
	250	29,000	102	10.79	2.25	
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	8.62	1.96	
	150	16,000	62	8.62	1.96	
HADCO Techtra, HPS	100	9,500	43	16.94	3.06	
	150	16,000	62	16.72	3.03	
	250	29,000	102	16.55	3.01	
HADCO Westbrooke, HPS	70	6,300	30	11.01	2.28	
	100	9,500	43	10.59	2.22	
	150	16,000	62	15.12	2.81	
	200	22,000	79	10.77	2.25	
	250	29,000	102	11.34	2.32	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						
Flood, Metal Halide	350	30,000	139	$ 5.91	$ 1.75	(I)
Flood, HPS	750	105,000	285	9.09	2.83	(I)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$ 10.65	$ 0.34	(I)
	30	11.44	0.37	(I)
	35	12.71	0.41	(R)
Aluminum Davit	25	10.69	0.34	(I)
	30	11.26	0.36	
	35	12.40	0.40	
	40	16.31	0.52	
Aluminum Double Davit	30	15.36	0.49	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Fluted Ornamental	14	$ 9.57	$ 0.31	(I)
Aluminum, HADCO, Smooth Techtra Ornamental	18	19.82	0.63	
Aluminum, Fluted Ornamental	16	10.32	0.33	
Aluminum, HADCO, Fluted Westbrooke	18	19.18	0.61	
Aluminum, HADCO, Smooth Westbrooke	18	19.77	0.63	
Fiberglass, Fluted Ornamental Black	14	11.10	0.35	
Fiberglass, Anchor Base, Gray or Black	35	13.02	0.42	(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Metal Halide	150	10,000	60	$ 5.37	$ 1.79	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	4.81	1.47	
	250	10,000	94	*	*	
	400	21,000	147	5.73	1.59	
	1,000	55,000	374	5.96	1.86	
Holophane Mongoose, HPS	150	16,000	62	8.86	2.00	
	250	29,000	102	8.31	1.93	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.81	*	
Mercury Vapor	175	7,000	66	5.77	1.57	(I)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Box, Anodized Aluminum						
Similar to GardCo Hub						
HPS - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$ 1.90	(I)
	150	16,000	62	*	1.92	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.25	
	400	40,000	156	*	1.25	
Cobrahead, Metal Halide	175	12,000	71	*	1.66	
Flood, Metal Halide	400	40,000	156	$ 6.09	1.81	
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	100	9,500	43	*	1.53	
100/150 Watt Ballast	150	16,000	62	*	1.55	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.70	
	165	12,000	60	*	0.83	
HADCO Techtra, QL	165	12,000	60	17.97	1.08	
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.39	
KIM Archetype, HPS	250	29,000	102	*	2.44	
	400	50,000	163	*	2.13	
Special Acorn-Type, HPS	70	6,300	30	8.50	1.98	(I)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$ 5.16	$ 1.50	(I)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.17	1.51	
Flood, HPS	70	6,300	30	4.76	1.42	
	100	9,500	43	4.74	1.52	
	200	22,000	79	5.93	1.64	
Cobrahead, HPS						
Power Door	310	37,000	124	5.96	1.92	(I)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.47	*	(I)
Aluminum, Painted Ornamental	35	*	$ 0.97	
Aluminum, Regular	16	6.47	0.21	
Bronze Alloy GardCo	12	*	0.19	
Concrete, Ornamental	35 or less	10.65	0.34	
Fiberglass, Direct Bury with Shroud	18	7.59	0.24	
Steel, Painted Regular **	25	10.65	0.34	
Steel, Painted Regular **	30	11.44	0.37	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.40	
Wood, Laminated without Mast Arm	20	4.79	0.15	
Wood, Laminated Street Light Only	20	4.79	*	
Wood, Curved Laminated	30	6.62	0.24	
Wood, Painted Underground	35	5.28	0.17	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.163	¢ per kWh	(I)
Distribution Charge	3.123	¢ per kWh	(I)
Energy Charge	5.322	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

In addition to the service rates for Option A lights, all Customers will pay the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Transmission and Related Services Charge	0.155 ¢ per kWh	(I)
Distribution Charge	6.475 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.177 ¢ per kWh	(I)

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.307¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Price Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the applicable daily Energy price by 1.0685.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [1]
	$140.00 per hour	$203.00 per hour

[1] Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Cobrahead Equivalent	37	2,530	13	$ 2.85	**(R)**
Cobrahead Equivalent	50	3,162	17	2.82	
Cobrahead Equivalent	52	3,757	18	3.17	
Cobrahead Equivalent	67	5,050	23	3.33	
Cobrahead Equivalent	106	7,444	36	3.62	**(R)**
Cobrahead Equivalent	134	14,200	46	7.15	**(I)**
Cobrahead Equivalent	156	16,300	53	7.65	**(R)**
Cobrahead Equivalent	176	18,300	60	8.54	**(I)**
Cobrahead Equivalent	201	21,400	69	8.03	**(I)**

SCHEDULE 95 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 10.87	(I)
	70	4,332	24	11.79	(R)
HADCO Acorn LED	70	5,120	24	15.43	(R)
Westbrooke (Non-Flared)	36	3,369	12	14.56	(I)
LED	53	5,079	18	15.84	|
	69	6,661	24	15.10	|
	85	8,153	29	15.73	|
	136	12,687	46	17.32	|
	206	18,159	70	17.04	|
Westbrooke (Flared)	36	3,369	12	14.92	(I)
LED	53	5,079	18	16.38	(R)
	69	6,661	24	16.54	(I)
	85	8,153	29	17.26	(I)
	136	12,687	46	16.94	(R)
	206	18,159	70	18.32	(I)
Post-Top, American Revolution	45	3,395	15	6.88	|
LED	72	4,409	25	6.38	(I)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule. Consistent with the requirements of the Bonneville Power Administration (BPA), if, in the course of doing business, a utility discovers that one of its existing Customers is growing Cannabis using power provided by the utility, such customer is not eligible for the Regional Power Act Exchange Credit under this Schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits inclusive provided in accordance with the terms of the Settlement Agreement between the Company and the BPA.

The credit inclusive of interest is:

Schedule 7			
First 1,000 kWh	(0.931)	¢ per kWh	**(I)**
Over 1,000 kWh	(0.500)	¢ per kWh	**(R)**
All other schedules	(0.835)	¢ per kWh	**(R)**

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects (including associated transmission) not otherwise included in rates. Additional new renewable and energy storage projects may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210, Section 13 of the Oregon Renewable Energy Act (OREA), and ORS 469A.120. (C) (C) (C)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495 and 576. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule			
7		0.000	¢ per kWh
15		0.000	¢ per kWh
32		0.000	¢ per kWh
38		0.000	¢ per kWh
47		0.000	¢ per kWh
49		0.000	¢ per kWh
75			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
83		0.000	¢ per kWh
85			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		
89		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
90	0.000	¢ per kWh
91	0.000	¢ per kWh
92	0.000	¢ per kWh
95	0.000	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements of a qualifying project will include the fixed costs of the renewable or energy storage resource and associated transmission (including return on and (C) return of the capital costs), operation and maintenance costs, income taxes, property taxes, and other fees and costs that are applicable to the renewable or energy storage resource or (C) associated transmission. Until the dispatch benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of each project (fixed costs less market value of the energy produced by the renewable or energy storage resource plus any power (C) costs such as fuel, integration and wheeling costs) will be deferred and incorporated the following January 1 into the Schedule 122 rates. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts. Each year by April 1, the Company will file an update to the revenue requirements of resources included in this schedule to recognize projected changes for the following calendar year.

DEFERRAL MECHANISM

For each calendar year that the Company anticipates that a new renewable or energy storage (C) resource will commence operation, the Company may file a deferral request the earlier of the resource online date or April 1. The deferral amount will be for the fixed revenue requirements of the resource less net dispatch benefits plus incremental expenses related to energy storage (C) as allowed in Oregon House Bill 2193. For purposes of determining dispatch benefits, the (C) forward curves used to set rates for the year under the Annual Power Cost Update will be used. The deferral will be amortized over the next calendar year in Schedule 122 unless otherwise approved by the Oregon Public Utility Commission (OPUC). The amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SCHEDULE 122 (Continued)

TIME AND MANNER OF FILING

For each calendar year that the Company is required to update the renewable or energy storage Resource Annual Revenue Requirements or proposes to include a new resource under this schedule, the Company will file by no later than April 1, the following: (C)

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate "taxes authorized to be collected in rates" under ORS 757.268.

2. Within the Company's Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

By December 1, the Company will file the updated rates that are in compliance with the Commission's findings in the proceeding reviewing the April 1 filing.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as "renewable" in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable or energy storage resource project or each separately identifiable project segment will be verified by an attestation from the Company stating that the specific renewable resource project, or project segment, has met requirements for being commercially operational and is in service. (C)

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, differences between: (C)

a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to kWh Energy sales; and

b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer to the numbers of active Customers for each applicable SNA rate schedule, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 69% of the Monthly Fixed Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review. (C)

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual revenues and will accrue to the SNA Balancing Account. Prior to 2019, the actual revenues in the SNA calculation will be weather normalized. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for each rate schedule will track separately. **(C)**

The SNA is applicable to the following rate schedules: **(N)**

Schedule	Fixed Charge Energy Rate (¢ per kWh)	Monthly Fixed Charge	Monthly Secondary Fixed Charge
7	9.047	$ 72.41	$ 49.96
32	8.092	$ 114.54	
38*	11.095	$ 722.04	
47*	14.633	$ 86.67	
49*	11.501	$ 477.34	
83*	3.915	$ 791.63	
85*			
Secondary	3.777	$ 4,823.69	
Primary	3.710	$ 7,613.93	
532	8.092	$ 114.54	
538*	11.095	$ 722.04	
549*	11.501	$ 477.34	

*Applicable beginning in 2019. The Fixed Charge Energy Rate for Schedules 83, 85, 583, and 585 include fixed generation charges only. **(N)**

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA) (M)

For EEMs installed prior to 2019, the Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates. (C)

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 6.278 cents per kWh. (M)

SCHEDULE 123 (Continued)

SNA and LRRA BALANCING ACCOUNTS (M)

The Company will maintain a separate balancing account for the SNA applicable rate schedules (C) and for the Nonresidential LRRA applicable rate schedules. Each balancing account will record (C) over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate	
7	0.009 ¢ per kWh	(I)
15	(0.008) ¢ per kWh	
32	(0.070) ¢ per kWh	
38	(0.008) ¢ per kWh	
47	(0.008) ¢ per kWh	
49	(0.008) ¢ per kWh	
75		
Secondary	(0.008) ¢ per kWh	
Primary	(0.008) ¢ per kWh	
Subtransmission	(0.008) ¢ per kWh	
83	(0.008) ¢ per kWh	
85		
Secondary	(0.008) ¢ per kWh	
Primary	(0.008) ¢ per kWh	
89		
Secondary	(0.008) ¢ per kWh	
Primary	(0.008) ¢ per kWh	
Subtransmission	(0.008) ¢ per kWh	(I)(M)

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued) (M)

Schedule	Adjustment Rate	
90	(0.008) ¢ per kWh	(I)
91	(0.008) ¢ per kWh	
92	(0.008) ¢ per kWh	
95	(0.008) ¢ per kWh	
485		
Secondary	(0.002) ¢ per kWh	
Primary	(0.002) ¢ per kWh	
489		
Secondary	(0.002) ¢ per kWh	
Primary	(0.002) ¢ per kWh	
Subtransmission	(0.002) ¢ per kWh	
490	(0.002) ¢ per kWh	
491	(0.002) ¢ per kWh	
492	(0.002) ¢ per kWh	
495	(0.002) ¢ per kWh	
515	(0.008) ¢ per kWh	
532	(0.070) ¢ per kWh	
538	(0.008) ¢ per kWh	
549	(0.008) ¢ per kWh	
575		
Secondary	(0.008) ¢ per kWh	
Primary	(0.008) ¢ per kWh	
Subtransmission	(0.008) ¢ per kWh	
583	(0.008) ¢ per kWh	(I)(M)

SCHEDULE 123 (Continued) (T)

DECOUPLING ADJUSTMENT (Continued) (M)

Schedule	Adjustment Rate	
585		
Secondary	(0.008) ¢ per kWh	(I)
Primary	(0.008) ¢ per kWh	
589		
Secondary	(0.008) ¢ per kWh	
Primary	(0.008) ¢ per kWh	
Subtransmission	(0.008) ¢ per kWh	
590	(0.008) ¢ per kWh	
591	(0.008) ¢ per kWh	
592	(0.008) ¢ per kWh	
595	(0.008) ¢ per kWh	(I)

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA. (C)(M)

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS (M)

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. If the amount of the proposed rate revision exceeds the 2% limit, only a 2% rate increase will be proposed and any remaining amount in the SNA balancing Account will be carried over to the following year(s). Rate revisions resulting in a rate decrease are not subject to the 2% limit. (C)

3. The LRRA prices for Customers served under the provisions of Schedules 485, 489, 490, 491, 492, and 495 will be calculated to apply to distribution services only.

4. The LRRA mechanism will terminate on December 31, 2018.

5. The SNA mechanism will terminate on December 31, 2022 if not extended by the Commission. (C) (M)

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0322. **(R)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 490, 491, 492, 495, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 595, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0322 (R)
to account for franchise fees, uncollectibles, and OPUC fees.

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, and 495 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.
- Include actual State and Federal Production Tax Credits.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0322 to account for franchise fees, uncollectables, and OPUC fees. **(R)**

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2018, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2019: (C)
(C)

Schedule		Annual ¢ per kWh [1]	
32		3.489	(I)
38		2.982	
75	Secondary	2.926 [2]	
	Primary	2.872 [2]	
	Subtransmission	2.891 [2]	
83		3.434	
85	Secondary	3.240	
	Primary	3.157	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh (1)	
89	Secondary	2.926	(I)
	Primary	2.872	
	Subtransmission	2.891	
90		2.696	
91		2.762	
95		2.762	
515		2.762	
532		3.489	
538		2.982	
549		4.427	
575	Secondary	2.926 (2)	
	Primary	2.872 (2)	
	Subtransmission	2.891 (2)	
583		3.434	
585	Secondary	3.240	
	Primary	3.157	
589	Secondary	2.926	
	Primary	2.872	
	Subtransmission	2.891	
590		2.696	
591		2.762	
592		2.766	
595		2.762	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

Commencing with enrollment Period M, the Schedule 129 Transition Cost Adjustment will be updated to reflect OPUC-approved changes in fixed generation costs during the five-year period.

For Enrollment Period M (2014), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2015	1.712	1.704	1.443	1.415	1.383	1.381	1.311	
2016	2.172	2.151	1.890	1.854	1.824	1.798	1.789	
2017	2.196	2.174	1.913	1.876	1.846	1.820	1.811	
2018	2.347	2.326	2.008	1.969	1.929	1.911	1.851	
2019	2.292	2.272	1.876	1.841	1.812	1.798	1.794	(R)
After 2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period N (2015), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2016	2.866	2.832	2.695	2.647	2.590	2.295	2.455	
2017	2.890	2.855	2.718	2.669	2.612	2.317	2.477	
2018	3.041	3.007	2.813	2.762	2.695	2.408	2.517	
2019	2.986	2.953	2.681	2.727	2.578	2.295	2.460	(R)
2020	2.986	2.953	2.681	2.727	2.578	2.295	2.460	(R)
After 2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period O (2016), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2017	3.015	2.963	2.854	2.803	2.739	2.431	2.586	
2018	3.113	3.063	2.899	2.847	2.774	2.473	2.578	
2019	2.873	2.823	2.735	2.687	2.625	2.328	2.490	(R)
2020	2.873	2.823	2.735	2.687	2.625	2.328	2.490	|
2021	2.873	2.823	2.735	2.687	2.625	2.328	2.490	(R)
After 2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

For Enrollment Period P (2017), the current Transition Cost Adjustments are:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2018	3.339	3.294	3.007	2.953	2.892	2.732	2.805	
2019	3.099	3.054	2.843	2.793	2.743	2.587	2.717	(R)
2020	3.099	3.054	2.843	2.793	2.743	2.587	2.717	|
2021	3.099	3.054	2.843	2.793	2.743	2.587	2.717	|
2022	3.099	3.054	2.843	2.793	2.743	2.587	2.717	(R)
After 2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

SCHEDULE 129 (Concluded)

SPECIAL CONDITIONS (Continued)

3. In determining changes in fixed generation revenues from movement to or from Schedules 485, 489, 490, 491, 492, and 495, the following factors will be used:

Schedule		¢ per kWh	
85	Secondary	3.765	(R)
	Primary	3.698	
89	Secondary	3.525	
	Primary	3.460	
	Subtransmission	3.414	
90		3.434	
91		3.346	
92		3.346	
95		3.346	(R)

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 485, 489, 490, 491, 492 or 495.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON DEPOSITS (See Rules E and K)

1.4% per annum.

BILLING RATES (Rules E, F, H and J)

Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours [1]	No charge	
Other than Scheduled Crew Hours [1]	$170.00	
Returned Payment Charge	$ 25.00	
Special Meter Reading Charge (non-network)	$ 17.00	(R)
Meter Test Charge	$ 75.00	
Late Payment Charge (monthly)	2.0% of delinquent balance	
Field Visit Charge [2]	$ 20.00	
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule F)	$ 32.00	
Portfolio Enrollment Charge	$ 5.00	
Customer Interval Data (12 months) to Customers	$100.00	
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$75.00	

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 6:30 a.m. to 10:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.

(2) See Rule H, Section 2 for applicable conditions.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects		
Monday through Friday	No charge	
Reconnection		
Standard Reconnection		
At Meter Base	$ 27.00	(R)
Other than Meter Base	$ 75.00	
After Hours Reconnection(1)		
At Meter Base	$ 80.00	
Other than Meter Base	$160.00	

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)(2)(3)

Disconnects		
Standard		
At Meter Base	No charge	
Other than Meter Base	No charge	
		(D)
Reconnects		
Standard		
Safety related	No charge	
Non-safety related		
At Meter Base	$ 27.00	(R)
Other than Meter Base	$ 75.00	
		(D)

(1) PGE representatives will be dispatched to reconnect service until 7:00 p.m., Monday through Friday. As such, crews dispatch up to and including 7:00 p.m. may be reconnecting service after 7:00 p.m. State- and utility-recognized holidays are excluded from the after hours provision.

(2) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

(3) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule H(4).

SCHEDULE 300 (Continued)

(D)

NON-NETWORK RESIDENTIAL METER RATES (Rule M)

Installation of non-network meter (one time charge)	$80.00	(R) (M)
Non-network Meter Read	$ 17.00 per month	(R)

METER RELOCATION RATES (Rule M)

Single meter relocation	Estimated Actual Costs
Single meter relocation with Pole	Estimated Actual Costs

MISCELLANEOUS EQUIPMENT RENTAL (Rule C)

Rental of transformers, single-phase to three-phase inverters, capacitors, and other related equipment	1-2/3% per month of current replacement cost at time of installation

TRANSFORMERS (Rule I Section 3)

Submersible Transformers[(1)]

Subdivision - eight dwelling units or more	$ 250.00 per lot $1,970.00 minimum	(C)(I) (I)
Mobile Home - eight spaces or more	$ 250.00 per space $1,970.00 minimum	(C)(I) (I)
Multi-Family Units - twenty units or more	$ 100.00 per family unit $1,970.00 minimum	(C)(I) (I)

(1) For all other applications, which include but are not limited to network service areas and densely populated urban areas, that require submersible transformers, the charge will be the calculated difference in cost between submersible and pad-mount transformer installations including the costs of future maintenance. (M)

SCHEDULE 300 (Continued)

(D)
(M)

TRANSFORMERS

Transformer Content

Upon request, PGE will research its records to provide a customer with Polychlorinated Biphenyls (PCB) content of a PGE transformer. Records searches could reveal the PCB content in specified transformer or that the PCB content is unknown. In the situation where the PCB content is unknown, an additional request can be made to test the PCB concentration.

Research Transformer PCB Content	
PCB Content-Specific Transformer	$75.00 per Transformer(1)
Additional Request	
Concentration Test	Site-by-Site Basis(2)

PCB Records Request

To request a records search to determine the PCB content of PGE equipment, please contact PGE's Environmental Services to request a PCB Inquiry form. The form can be sent electronically or by postal service, if needed. Complete the form and return it, along with payment to: PGE PCB Inquiry, 121 SW Salmon Street, WTCBR05, Portland, OR 97204. Checks are made payable to PGE PCB Inquiry and submitted with the PCB Inquiry form.

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(1) PGE transformers often have stickers which indicate the PCB concentration of the oil within that transformer. The Customer may determine the content by observing the sticker. The PCB content of equipment with green stickers is unknown. However, blue stickers indicate <1 parts per million (PPM) PCB, red stickers indicate <15 ppm PCB, and black stickers indicate <48 ppm PCB.

(2) The additional cost of testing PCB concentration is determined on a site-by-site basis, and based on whether the following activities are required: de-energizing equipment, collecting samples, contracting sample analyses, and preparation of a summary report. In some instances, a proposal from a contractor may be required. (M)

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule I) (M)

Line Extension Allowance (Section 1)

Residential Service	$1,623.00 / dwelling unit
Schedule 32	$0.1473 / estimated annual kWh
Schedules 38 and 83	$0.0780 / estimated annual kWh
Schedules 85 and 89 Secondary Voltage Service	$0.0531 / estimated annual kWh
Schedules 85 and 89 Primary Voltage Service	$0.0264 / estimated annual kWh
Schedules 15, 91 and 95 Outdoor Lighting	$0.0850 / estimated annual kWh
Schedule 92 Traffic Signals	$0.0531 / estimated annual kWh
Schedules 47 and 49	$0.0336 / estimated annual kWh

Trenching or Boring (Section 2)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas[(1)]

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

(1) Applies only to 1-inch conduit without brackets. (M)

SCHEDULE 300 (Concluded) (T)

(M)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$795.00	(I)
Permanent Customer obtained		
Overhead Service	$490.00	
Underground Service	$450.00	
Existing service	$260.00	
Enhanced Temporary Service		
Fixed fee for 12-month period	$430.00	(I)
Temporary Area Lights	Estimated Actual Cost[3]	(C)

(D)

PGE TRAINING

Educational and Energy Efficiency (EE) training available to:

PGE Business Customer	No Charge[1]
Non-PGE Business Customer	Estimated Actual Cost[2]

(1) Charges may be assessed for training courses registered through the states of Oregon and Washington for electrical licensees. (M)

(2) Based on the cost associated with instructor, facility, food, and materials per attendee. (N)

(3) Based on install, removal and energy for pole and luminaire. Energy will be calculated based on burning hours used for Option C Schedule 91, 95 (N)

SCHEDULE 310
DEPOSITS FOR RESIDENTIAL SERVICE

PURPOSE

The purpose of this schedule is to list the deposits for residential service referred to in Rule D of the General Rules and Regulations. PGE will calculate a deposit amount representative of one-sixth (1/6) of the customer's estimated average annual bill. In the event that calculation of one-sixth of the customer's estimated annual bill is not possible, PGE will assess a deposit amount in accordance with the estimates below, based on customer dwelling type. (C) (C)

DEPOSIT AMOUNTS	Average Deposit
Single-Family Dwellings	
All electric (electric heat, hot water, range, and lights)	$229.00
Electric heat but not all electric	$177.00
Electric hot water, range, and lights	$160.00
Any other combination	$132.00
Multiple-Family Dwellings	
All electric	$129.00
Electric heat but not all electric	$108.00
Electric hot water, range, and lights	$108.00
Any other combination	$72.00
Mobile Homes	
All electric	$203.00
Any other combination	$130.00
Houseboats	
All electric	$122.00
Any other combination	$89.00

(D)

SCHEDULE 485
LARGE NONRESIDENTIAL
COST OF SERVICE OPT-OUT
(201 - 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Customers with existing enrolled PODs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional PODs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage Secondary	Delivery Voltage Primary	
Basic Charge	$590.00	$490.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.27	$3.20	(R)(I)
Over 200 kW	$2.07	$2.00	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	(R)
System Usage Charge			
per kWh	(0.014) ¢	(0.015) ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 489
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW more than once within the preceding 13 months and who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Customers with existing enrolled PODs meeting the 1 MWa criteria above may, in a subsequent enrollment window enroll additional PODs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495. Beginning with the September 2004 Enrollment Period*** C, Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,540.00	$2,040.00	$4,190.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.52	$1.48	$1.48	(R)
Over 4,000 kW	$1.21	$1.17	$1.17	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	$1.29	(R)(I)
System Usage Charge				
per kWh	0.002 ¢	0.000 ¢	0.000 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 490
LARGE NONRESIDENTIAL
COST-OF-SERVICE OPT-OUT
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has previously enrolled in a long-term opt-out window. To obtain service under this schedule, Customers must initially enroll a minimum of 1 MWa determined by a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Customers with existing enrolled PODs meeting the 1 MWa criteria above may, in a subsequent enrollment window*** enroll additional PODs so long as the 250 kW Facility Capacity requirement is met. Service under this schedule is limited to the first 300 MWa that applies to this and Schedules 485 489, 490, 491, 492, and 495. Customers have a minimum five-year option and a fixed three-year option.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$6,600.00	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.59	(I)
Over 4,000 kW	$1.28	(I)
per kW of monthly On-Peak Demand	$2.58	(R)
System Usage Charge		
per kWh	(0.060) ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

*** A list of Enrollment Periods can be found in Schedule 129.

SCHEDULE 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 6.338 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [(1)]
	$140.00 per hour	$203.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 3.19	$ 1.90	(I)
	100	9,500	43	*	4.01	2.73	
	150	16,000	62	*	5.22	3.93	
	200	22,000	79	*	6.33	5.01	
	250	29,000	102	*	7.76	6.46	
	400	50,000	163	*	11.67	10.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.75	3.41	1.90	
	100	9,500	43	7.58	4.24	2.73	
	150	16,000	62	8.89	5.46	3.93	
	200	22,000	79	10.73	6.59	5.01	
	250	29,000	102	12.06	8.02	6.46	
	400	50,000	163	16.00	11.90	10.33	
Flood	250	29,000	102	12.35	8.06	6.46	
	400	50,000	163	16.22	11.93	10.33	
Early American Post-Top	100	9,500	43	7.95	4.29	2.73	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	8.06	3.59	1.90	
	100	9,500	43	8.58	4.38	2.73	
	150	16,000	62	10.09	5.62	3.93	(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black, Bronze or Gray	20	$ 4.79	$ 0.15	(I)
Fiberglass, Black or Bronze	30	7.43	0.24	
Fiberglass, Gray	30	8.05	0.26	
Fiberglass, Smooth, Black or Bronze	18	5.04	0.16	
Fiberglass, Regular	18	4.21	0.13	
Black, Bronze, or Gray	35	7.50	0.24	
Wood, Standard	30 to 35	5.28	0.17	(I)
Wood, Standard	40 to 55	6.27	0.20	(R)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$ 11.20	$ 4.68	$ 2.73	(I)
HADCO Victorian, HPS	150	16,000	62	12.40	5.88	3.93	
	200	22,000	79	14.14	7.05	5.01	
	250	29,000	102	15.59	8.50	6.46	
HADCO Capitol Acorn, HPS	100	9,500	43	14.79	5.15	2.73	
	150	16,000	62	14.72	6.18	3.93	
	200	22,000	79	15.81	7.27	5.01	
	250	29,000	102	17.25	8.71	6.46	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.35	4.69	2.73	
	150	16,000	62	12.55	5.89	3.93	
HADCO Techtra, HPS	100	9,500	43	19.67	5.79	2.73	
	150	16,000	62	20.65	6.96	3.93	
	250	29,000	102	23.01	9.47	6.46	
HADCO Westbrooke, HPS	70	6,300	30	12.91	4.18	*	
	100	9,500	43	13.32	4.95	2.73	(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	$ 19.05	$ 6.74	$ 3.93	(I)
	200	22,000	79	15.78	7.26	5.01	
	250	29,000	102	17.80	8.78	6.46	
Special Types							
Flood, Metal Halide	350	30,000	139	14.72	10.56	8.81	
Flood, HPS	750	105,000	285	27.15	20.89	18.06	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.06	
Ornamental Acorn	55	2,800	21	*	*	1.33	
Ornamental Acorn Twin	55	5,600	42	*	*	2.66	
Composite, Twin	140	6,815	54	*	*	3.42	
	175	9,815	66	*	*	4.18	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$ 10.65	$ 0.34	(I)
	30	11.44	0.37	(I)
	35	12.71	0.41	(R)
Aluminum Davit	25	10.69	0.34	(I)
	30	11.26	0.36	
	35	12.40	0.40	
	40	16.31	0.52	
Aluminum Double Davit	30	15.36	0.49	
Aluminum, Fluted Ornamental	14	9.57	0.31	(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Smooth Techtra Ornamental	18	$ 19.82	$ 0.63	(I)
Aluminum, Fluted Ornamental	16	10.32	0.33	
Aluminum, HADCO, Fluted Westbrooke	18	19.18	0.61	
Aluminum, HADCO, Smooth Westbrooke	18	19.77	0.63	
Fiberglass, Fluted Ornamental Black	14	11.10	0.35	
Fiberglass, Anchor Base, Gray or Black	35	13.02	0.42	(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Metal Halide	150	10,000	60	$ 9.17	$ 5.59	$ 3.80	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.47	
	175	7,000	66	8.99	5.65	4.18	
	250	10,000	94	*	*	5.96	
	400	21,000	147	15.05	10.91	9.32	
	1,000	55,000	374	29.66	25.56	23.70	
Holophane Mongoose, HPS	150	16,000	62	12.79	5.93	3.93	
	250	29,000	102	14.77	8.39	*	(I)

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.71	*	*	(I)
Mercury Vapor	175	7,000	66	9.95	$ 5.75	$ 4.18	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.80	
	70	6,300	30	*	*	1.90	
	100	9,500	43	*	4.63	2.73	
	150	16,000	62	*	5.85	3.93	
	250	29,000	102	*	*	6.46	
	400	50,000	163	*	*	10.33	
Metal Halide	250	20,500	99	*	7.52	6.27	
	400	40,000	156	*	11.14	*	
Cobrahead, Metal Halide	175	12,000	71	*	6.16	4.50	
Flood, Metal Halide	400	40,000	156	15.98	11.70	9.89	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	150	16,000	62	*	5.48	3.93	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	6.32	3.93	
KIM Archetype, HPS	250	29,000	102	*	8.90	6.46	
	400	50,000	163	*	12.46	10.33	(I)

* Not offered

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$ 10.40	$ 3.88	*	(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$ 1.90	
Mercury Vapor	175	7,000	66	*	*	4.18	
Early American Post-Top, HPS							
Black	70	6,300	30	7.06	3.40	1.90	
Rectangle Type	200	22,000	79	*	*	5.01	
Incandescent	92	1,000	31	*	*	1.96	
	182	2,500	62	*	*	3.93	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.35	5.69	4.18	
Flood, HPS	70	6,300	30	6.66	3.32	*	
	100	9,500	43	7.47	4.25	2.73	
	200	22,000	79	10.94	6.65	5.01	
Cobrahead, HPS							
Power Door	310	37,000	124	13.82	9.78	7.86	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.73	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.45	
Compact Fluorescent	28	N/A	12	*	*	0.76	(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.47	*	(I)
Aluminum, Painted Ornamental	35	*	$ 0.97	
Aluminum, Regular	16	6.47	0.21	
Bronze Alloy GardCo	12	*	0.19	
Concrete, Ornamental	35 or less	10.65	0.34	
Fiberglass, Direct Bury with Shroud	18	7.59	0.24	
Steel, Painted Regular **	25	10.65	0.34	
Steel, Painted Regular **	30	11.44	0.37	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.40	
Wood, Laminated without Mast Arm	20	4.79	0.15	
Wood, Laminated Street Light Only	20	4.79	*	
Wood, Curved Laminated	30	6.62	0.24	
Wood, Painted Underground	35	5.28	0.17	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.73	$ 2.03	(I)
	165	12,000	60	*	4.63	3.80	
	165	12,000	60	$ 21.77	4.88	3.80	(I)

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.982 ¢ per kWh	**(I)**

* See Schedule 100 for applicable adjustments.

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 6.338 ¢ per kWh **(I)**

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

	Straight Time	Overtime
Labor Rates (1)	$140.00 per hour	$203.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$ 3.67	(R)
LED	50	3,162	17	3.90	|
LED	52	3,757	18	4.31	|
LED	67	5,050	23	4.79	|
LED	106	7,444	36	5.90	(R)
LED	134	14,200	46	10.07	(I)
LED	156	16,300	53	11.01	(R)
LED	176	18,300	60	12.34	(I)
LED	201	21,400	69	12.40	(I)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 12.20	(I)
	70	4,332	24	13.31	(R)
HADCO Acorn LED	70	5,120	24	16.95	(R)
Westbrooke (Non-Flared)	36	3,369	12	15.32	(I)
LED	53	5,079	18	16.98	
	69	6,661	24	16.62	
	85	8,153	29	17.57	
	136	12,687	46	20.24	
	206	18,159	70	21.48	
Westbrooke (Flared)	36	3,369	12	15.68	(I)
LED	53	5,079	18	17.52	(R)
	69	6,661	24	18.06	(I)
	85	8,153	29	19.10	(I)
	136	12,687	46	19.86	(R)
	206	18,159	70	22.76	(I)
Post-Top, American Revolution	45	3,395	15	7.83	
LED	72	4,409	25	7.96	(I)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$ 8.91 [2]	(R)
	400	21,000	147	14.59 [2]	(R)
	1,000	55,000	374	29.20 [2]	(I)
HPS	70	6,300	30	6.67 [2]	(R)
	100	9,500	43	7.50	
	150	16,000	62	8.81	
	200	22,000	79	10.27	
	250	29,000	102	11.60	
	310	37,000	124	13.36 [2]	
	400	50,000	163	15.54	
Flood , HPS	100	9,500	43	7.39 [2]	
	200	22,000	79	10.48 [2]	
	250	29,000	102	11.89	
	400	50,000	163	15.76	
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.98	
	100	9,500	43	8.50	
	150	16,500	62	10.02	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Special Acorn Type, HPS	100	9,500	43	$ 10.75	(R)
HADCO Victorian, HPS	150	16,500	62	11.95	
	200	22,000	79	13.69	
	250	29,000	102	15.14	
Early American Post-Top, HPS, Black	100	9,500	43	7.88	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.10	
Cobrahead, Metal Halide	175	12,000	71	9.87	
Flood, Metal Halide	350	30,000	139	14.26	
Flood, Metal Halide	400	40,000	156	15.52	
Flood, HPS	750	105,000	285	26.69	
HADCO Independence, HPS	100	9,500	43	10.90	
	150	16,000	62	12.10	
HADCO Capitol Acorn, HPS	100	9,500	43	14.33	
	150	16,000	62	14.26	
	200	22,000	79	15.36	
	250	29,000	102	16.79	
HADCO Techtra, HPS	100	9,500	43	19.21	
	150	16,000	62	20.19	
	250	29,000	102	22.55	
HADCO Westbrooke, HPS	70	6,300	30	12.45	
	100	9,500	43	12.86	
	150	16,000	62	18.59	
	200	22,000	79	15.32	
	250	29,000	102	17.34	
Holophane Mongoose, HPS	150	16,000	62	12.33	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Acorn					
LED	60	5,488	21	$ 11.74	(R)
	70	4,332	24	12.86	
HADCO LED	70	5,120	24	16.49	
Cobrahead					
LED	37	2,530	13	4.02	
	50	3,162	17	4.25	
	52	3,757	18	4.66	
	67	5,050	23	5.02	
	106	7,444	36	6.13	(R)
	134	14,200	46	9.61	(I)
	156	16,300	53	10.56	(R)
	176	18,300	60	11.88	(I)
	201	21,400	69	11.95	
Westbrooke LED (Non-Flare)	36	3,369	12	14.86	
	53	5,079	18	16.52	
	69	6,661	24	16.16	(I)
	85	8,153	29	17.11	(R)
	136	12,687	46	19.78	
	206	18,159	70	21.02	(R)
Westbrooke LED (Flare)	36	3,369	12	15.22	(I)
	53	5,079	18	17.07	(R)
	69	6,661	24	17.60	(R)
	85	8,153	29	18.64	(I)
	136	12,687	46	19.40	(R)
	206	18,159	70	22.30	
CREE XSP LED	25	2,529	9	2.87	
	42	3,819	14	3.28	
	48	4,373	16	3.80	
	56	5,863	19	4.42	
	91	8,747	31	5.18	(R)
Post-Top, American Revolution					
LED	45	3,395	15	7.37	(I)
	72	4,409	25	7.50	(I)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$ 5.18	(I)
	40 to 55	6.17	(R)
			(I)
Wood, Painted Underground	35 or less	5.18 [2]	
Wood, Curved laminated	30 or less	6.51 [2]	
Aluminum, Regular	16	6.39	
	25	10.52	
	30	11.31	(I)
	35	12.59	(R)
Aluminum, Fluted Ornamental	14	9.50	(I)
Aluminum Davit	25	10.57	
	30	11.13	
	35	12.28	
	40	16.15	
Aluminum Double Davit	30	15.23	
Aluminum, Fluted Ornamental	16	10.24	
Aluminum, HADCO, Smooth Techtra Ornamental	18	19.69	
Aluminum, HADCO, Fluted Westbrooke	18	19.05	
Aluminum, HADCO, Smooth Westbrooke	18	19.64	
Concrete, Ameron Post-Top	25	17.79	
Fiberglass Fluted Ornamental; Black	14	11.00	
Fiberglass, Regular			
Black	20	4.72	
Gray or Bronze	30	7.92	
Black, Gray, or Bronze	35	7.40	
Fiberglass, Anchor Base, Gray or Black	35	12.92	
Fiberglass, Direct Bury with Shroud	18	7.47	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$20.00	(I)
Three Phase	$29.00	(I)
Distribution Charge		
First 5,000 kWh	4.383 ¢ per kWh	(I)
Over 5,000 kWh	1.354 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2015.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$30.00		(I)
Distribution Charge	7.400	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$45.00	(I)
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	8.225 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.225 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$3,540.00	$2,040.00	$4,190.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.52	$1.48	$1.48	(R)
Over 4,000 kW	$1.21	$1.17	$1.17	(R)
per kW of monthly On-Peak Demand**	$2.66	$2.58	$1.29	(R)(I)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.002 ¢	0.000 ¢	0.000 ¢	(I)

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.104	$0.101	$0.050	(I)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

Basic Charge		
Single Phase Service	$35.00	(I)
Three Phase Service	$45.00	(I)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.60	(R)
Over 30 kW	$3.50	(R)
per kW of monthly On-Peak Demand	$2.66	(R)
System Usage Charge		
per kWh	0.617 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge	$590.00	$490.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.27	$3.20	(R)(I)
Over 200 kW	$2.07	$2.00	(R)
per kW of monthly On-Peak Demand	$2.66	$2.58	(R)
System Usage Charge			
per kWh	(0.014) ¢	(0.015) ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$3,540.00	$2,040.00	$4,190.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$1.52	$1.48	$1.48	(R)
Over 4,000 kW	$1.21	$1.17	$1.17	(R)
per kW of monthly on-peak Demand	$2.66	$2.58	$1.29	(R)(I)
System Usage Charge				
per kWh	0.002 ¢	0.000 ¢	0.000 ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

<u>Basic Charge</u>	$6,600.00	(I)
<u>Distribution Charges</u>**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$1.59	(I)
Over 4,000 kW	$1.28	(I)
per kW of monthly on-peak Demand	$2.58	(R)
<u>System Usage Charge</u>		
per kWh	(0.060) ¢	(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	6.338 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

NOVEMBER ELECTION WINDOW

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$140.00 per hour	$203.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **							
	70	6,300	30	*	$ 3.19	$ 1.90	(I)
	100	9,500	43	*	4.01	2.73	
	150	16,000	62	*	5.22	3.93	
	200	22,000	79	*	6.33	5.01	
	250	29,000	102	*	7.76	6.46	
	400	50,000	163	*	11.67	10.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.75	3.41	1.90	
	100	9,500	43	7.58	4.24	2.73	
	150	16,000	62	8.89	5.46	3.93	
	200	22,000	79	10.73	6.59	5.01	
	250	29,000	102	12.06	8.02	6.46	
	400	50,000	163	16.00	11.90	10.33	
Flood	250	29,000	102	12.35	8.06	6.46	
	400	50,000	163	16.22	11.93	10.33	
Early American Post-Top	100	9,500	43	7.95	4.29	2.73	
Shoebox (Bronze color, flat Lens, or drop lens, multi-volt)	70	6,300	30	8.06	3.59	1.90	
	100	9,500	43	8.58	4.38	2.73	
	150	16,000	62	10.09	5.62	3.93	(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black, Bronze or Gray	20	$ 4.79	$ 0.15	(I)
Fiberglass, Black or Bronze	30	7.43	0.24	
Fiberglass, Gray	30	8.05	0.26	
Fiberglass, Smooth, Black or Bronze	18	5.04	0.16	
Fiberglass, Regular	18	4.21	0.13	
Black, Bronze, or Gray	35	7.50	0.24	
Wood, Standard	30 to 35	5.28	0.17	(I)
Wood, Standard	40 to 55	6.27	0.20	(R)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$ 11.20	$ 4.68	$ 2.73	(I)
HADCO Victorian, HPS	150	16,000	62	12.40	5.88	3.93	
	200	22,000	79	14.14	7.05	5.01	
	250	29,000	102	15.59	8.50	6.46	
HADCO Capitol Acorn, HPS	100	9,500	43	14.79	5.15	2.73	
	150	16,000	62	14.72	6.18	3.93	
	200	22,000	79	15.81	7.27	5.01	
	250	29,000	102	17.25	8.71	6.46	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.35	4.69	2.73	
	150	16,000	62	12.55	5.89	3.93	
HADCO Techtra, HPS	100	9,500	43	19.67	5.79	2.73	
	150	16,000	62	20.65	6.96	3.93	
	250	29,000	102	23.01	9.47	6.46	
HADCO Westbrooke, HPS	70	6,300	30	12.91	4.18	*	
	100	9,500	43	13.32	4.95	2.73	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
HADCO Westbrooke, HPS	150	16,000	62	$ 19.05	$ 6.74	$ 3.93	(I)
	200	22,000	79	15.78	7.26	5.01	
	250	29,000	102	17.80	8.78	6.46	
Special Types							
Flood, Metal Halide	350	30,000	139	14.72	10.56	8.81	
Flood, HPS	750	105,000	285	27.15	20.89	18.06	
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	4.06	
Ornamental Acorn	55	2,800	21	*	*	1.33	
Ornamental Acorn Twin	55	5,600	42	*	*	2.66	
Composite, Twin	140	6,815	54	*	*	3.42	
	175	9,815	66	*	*	4.18	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	25	$ 10.65	$ 0.34	(I)
	30	11.44	0.37	(I)
	35	12.71	0.41	(R)
Aluminum Davit	25	10.69	0.34	(I)
	30	11.26	0.36	
	35	12.40	0.40	
	40	16.31	0.52	
Aluminum Double Davit	30	15.36	0.49	
Aluminum, Fluted Ornamental	14	9.57	0.31	(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Smooth Techtra Ornamental	18	$ 19.82	$ 0.63	(I)
Aluminum, Fluted Ornamental	16	10.32	0.33	
Aluminum, HADCO, Fluted Westbrooke	18	19.18	0.61	
Aluminum, HADCO, Smooth Westbrooke	18	19.77	0.63	
Fiberglass, Fluted Ornamental Black	14	11.10	0.35	
Fiberglass, Anchor Base, Gray or Black	35	13.02	0.42	(I)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Metal Halide	150	10,000	60	$ 9.17	$ 5.59	$ 3.80	(I)
Cobrahead, Mercury Vapor	100	4,000	39	*	*	2.47	
	175	7,000	66	8.99	5.65	4.18	
	250	10,000	94	*	*	5.96	
	400	21,000	147	15.05	10.91	9.32	
	1,000	55,000	374	29.66	25.56	23.70	
Holophane Mongoose,	150	16,000	62	12.79	5.93	3.93	
HPS	250	29,000	102	14.77	8.39	*	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.71	*	*	(I)
Mercury Vapor	175	7,000	66	9.95	$ 5.75	$ 4.18	
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.80	
	70	6,300	30	*	*	1.90	
	100	9,500	43	*	4.63	2.73	
	150	16,000	62	*	5.85	3.93	
	250	29,000	102	*	*	6.46	
	400	50,000	163	*	*	10.33	
Metal Halide	250	20,500	99	*	7.52	6.27	
	400	40,000	156	*	11.14	*	
Cobrahead, Metal Halide	175	12,000	71	*	6.16	4.50	
Flood, Metal Halide	400	40,000	156	15.98	11.70	9.89	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	100	9,500	43	*	4.26	*	
100/150 Watt Ballast	150	16,000	62	*	5.48	3.93	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	6.32	3.93	
KIM Archetype, HPS	250	29,000	102	*	8.90	6.46	
	400	50,000	163	*	12.46	10.33	(I)

* Not offered

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$ 10.40	$ 3.88	*	(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	$ 1.90	
Mercury Vapor	175	7,000	66	*	*	4.18	
Early American Post-Top, HPS							
Black	70	6,300	30	7.06	3.40	1.90	
Rectangle Type	200	22,000	79	*	*	5.01	
Incandescent	92	1,000	31	*	*	1.96	
	182	2,500	62	*	*	3.93	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	9.35	5.69	4.18	
Flood, HPS	70	6,300	30	6.66	3.32	*	
	100	9,500	43	7.47	4.25	2.73	
	200	22,000	79	10.94	6.65	5.01	
Cobrahead, HPS							
Power Door	310	37,000	124	13.82	9.78	7.86	
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.73	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	5.45	
Compact Fluorescent	28	N/A	12	*	*	0.76	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.47	*	(I)
Aluminum, Painted Ornamental	35	*	$ 0.97	
Aluminum, Regular	16	6.47	0.21	
Bronze Alloy GardCo	12	*	0.19	
Concrete, Ornamental	35 or less	10.65	0.34	
Fiberglass, Direct Bury with Shroud	18	7.59	0.24	
Steel, Painted Regular **	25	10.65	0.34	
Steel, Painted Regular **	30	11.44	0.37	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.36	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.36	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.40	
Wood, Laminated without Mast Arm	20	4.79	0.15	
Wood, Laminated Street Light Only	20	4.79	*	
Wood, Curved Laminated	30	6.62	0.24	
Wood, Painted Underground	35	5.28	0.17	(I)

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.73	$ 2.03	(I)
	165	12,000	60	*	4.63	3.80	
	165	12,000	60	$ 21.77	4.88	3.80	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.982 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge	6.338 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime (1)
	$140.00 per hour	$203.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$ 3.67	(R)
LED	50	3,162	17	3.90	
LED	52	3,757	18	4.31	
LED	67	5,050	23	4.79	
LED	106	7,444	36	5.90	(R)
LED	134	14,200	46	10.07	(I)
LED	156	16,300	53	11.01	(R)
LED	176	18,300	60	12.34	(I)
LED	201	21,400	69	12.40	(I)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 12.20	(I)
	70	4,332	24	13.31	(R)
HADCO Acorn LED	70	5,120	24	16.95	(R)
Westbrooke (Non-Flared)	36	3,369	12	15.32	(I)
LED	53	5,079	18	16.98	
	69	6,661	24	16.62	
	85	8,153	29	17.57	
	136	12,687	46	20.24	
	206	18,159	70	21.48	
Westbrooke (Flared)	36	3,369	12	15.68	(I)
LED	53	5,079	18	17.52	(R)
	69	6,661	24	18.06	(I)
	85	8,153	29	19.10	(I)
	136	12,687	46	19.86	(R)
	206	18,159	70	22.76	(I)
Post-Top, American Revolution	45	3,395	15	7.83	
LED	72	4,409	25	7.96	(I)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Painting or staining of wood and steel streetlight poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:	
7	0.337	¢ per kWh	Distribution Charge	(I)
15	0.548	¢ per kWh	Distribution Charge	(I)
32	0.307	¢ per kWh	Distribution Charge	(I)
38	0.352	¢ per kWh	Distribution Charge	(I)
47	0.522	¢ per kWh	Distribution Charge	(I)
49	0.375	¢ per kWh	Distribution Charge	(I)
75				
Secondary	0.170	¢ per kWh	System Usage Charge	(I)
Primary	0.167	¢ per kWh	System Usage Charge	(I)
Subtransmission	0.165	¢ per kWh	System Usage Charge	(I)

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
83	0.240 ¢ per kWh	System Usage Charge	(I)
85			
Secondary	0.201 ¢ per kWh	System Usage Charge	(I)
Primary	0.197 ¢ per kWh	System Usage Charge	(I)
89			
Secondary	0.170 ¢ per kWh	System Usage Charge	(I)
Primary	0.167 ¢ per kWh	System Usage Charge	(I)
Subtransmission	0.165 ¢ per kWh	System Usage Charge	(I)
90	0.153 ¢ per kWh	System Usage Charge	(I)
91	0.549 ¢ per kWh	Distribution Charge	(R)
92	0.219 ¢ per kWh	Distribution Charge	(I)
95	0.549 ¢ per kWh	Distribution Charge	(R)
485			
Secondary	0.069 ¢ per kWh	System Usage Charge	(R)
Primary	0.068 ¢ per kWh	System Usage Charge	(R)
489			
Secondary	0.046 ¢ per kWh	System Usage Charge	(R)
Primary	0.045 ¢ per kWh	System Usage Charge	(R)
Subtransmission	0.045 ¢ per kWh	System Usage Charge	(R)
490	0.015 ¢ per kWh	System Usage Charge	(I)
491	0.412 ¢ per kWh	Distribution Charge	(R)
492	0.077 ¢ per kWh	Distribution Charge	(I)
495	0.412 ¢ per kWh	Distribution Charge	(R)

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
515	0.411 ¢ per kWh	Distribution Charge	**(R)**
532	0.145 ¢ per kWh	Distribution Charge	**(I)**
538	0.202 ¢ per kWh	Distribution Charge	**(I)**
549	0.188 ¢ per kWh	Distribution Charge	**(I)**
575			
Secondary	0.046 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.045 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.045 ¢ per kWh	System Usage Charge	**(R)**
583	0.079 ¢ per kWh	System Usage Charge	**(I)**
585			
Secondary	0.069 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.068 ¢ per kWh	System Usage Charge	**(R)**
589			
Secondary	0.046 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.045 ¢ per kWh	System Usage Charge	**(R)**
Subtransmission	0.045 ¢ per kWh	System Usage Charge	**(R)**
590	0.015 ¢ per kWh	System Usage Charge	**(I)**
591	0.412 ¢ per kWh	Distribution Charge	**(R)**
592	0.077 ¢ per kWh	Distribution Charge	**(I)**
595	0.412 ¢ per kWh	Distribution Charge	**(R)**

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2019

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SDEC17E19)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT w/ Sch. 125, 122, 146	TOTAL ELECTRIC BILLS PROPOSED w/ Sch. 125, 122, 146	Change AMOUNT	Change PCT.
Residential	7	781,151	7,502,509	$939,337,556	$998,165,058	$58,827,502	6.3%
Employee Discount				($944,818)	($1,001,914)	($57,096)	
Subtotal				$938,392,738	$997,163,144	$58,770,406	6.3%
Outdoor Area Lighting	15	0	15,630	$3,427,428	$3,459,666	$32,238	0.9%
General Service <30 kW	32	93,656	1,590,863	$180,162,449	$192,869,869	$12,707,419	7.1%
Opt. Time-of-Day G.S. >30 kW	38	392	30,626	$4,068,295	$4,256,836	$188,541	4.6%
Irrig. & Drain. Pump. < 30 kW	47	3,031	21,544	$4,253,294	$4,457,924	$204,630	4.8%
Irrig. & Drain. Pump. > 30 kW	49	1,304	64,947	$9,423,730	$9,626,517	$202,787	2.2%
General Service 31-200 kW	83	11,349	2,753,722	$251,350,767	$260,917,449	$9,566,682	3.8%
General Service 201-4,000 kW							
Secondary	85-S	1,196	2,178,260	$174,298,132	$176,358,349	$2,060,218	1.2%
Primary	85-P	188	587,976	$44,019,683	$44,498,626	$478,943	1.1%
Schedule 89 > 4 MW							
Primary	89-P	13	469,240	$30,796,881	$31,413,644	$616,764	2.0%
Subtransmission	89-T	4	58,071	$4,261,061	$4,367,260	$106,199	2.5%
Schedule 90	90-P	4	1,758,397	$102,246,496	$105,483,770	$3,237,275	3.2%
Street & Highway Lighting	91/95	203	53,482	$11,616,802	$11,581,394	($35,408)	-0.3%
Traffic Signals	92	17	2,496	$205,446	$214,856	$9,410	4.6%
COS TOTALS		892,508	17,087,764	$1,758,523,202	$1,846,669,304	$88,146,102	5.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	225	565,248	$14,614,136	$13,827,058	($787,078)	-5.4%
Primary	485-P	51	316,338	$6,580,136	$6,161,233	($418,903)	-6.4%
Direct Access Service > 4 MW							
Secondary	489-S	1	13,399	$369,705	$302,784	($66,921)	-18.1%
Primary	489-P	14	888,772	$17,517,326	$16,378,179	($1,139,147)	-6.5%
Subtransmission	489-T	2	168,932	$1,108,883	$1,110,594	$1,710	0.2%
DIRECT ACCESS TOTALS		293	1,952,690	$40,190,186	$37,779,848	($2,410,338)	
COS AND DA CYCLE TOTALS		892,801	19,040,454	$1,798,713,388	$1,884,449,152	$85,735,764	4.8%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7

	Net Monthly Bill		
kWh	Current Prices	Proposed Prices	Percent Difference
50	$17.61	$19.99	13.5%
100	$23.08	$25.78	11.7%
200	$33.99	$37.32	9.8%
250	$39.45	$43.11	9.3%
300	$44.90	$48.89	8.9%
400	$55.81	$60.45	8.3%
500	$66.74	$72.01	7.9%
600	$77.60	$83.52	7.6%
700	$88.53	$95.09	7.4%
800	$99.43	$106.65	7.3%
850	$104.89	$112.42	7.2%
900	$110.35	$118.20	7.1%
1,000	$121.24	$129.74	7.0%
1,100	$133.95	$142.48	6.4%
1,200	$146.63	$155.20	5.8%
1,300	$159.35	$167.95	5.4%
1,400	$172.05	$180.70	5.0%
1,500	$184.76	$193.46	4.7%
1,600	$197.42	$206.16	4.4%
1,700	$210.13	$218.92	4.2%
1,800	$222.83	$231.65	4.0%
2,000	$248.22	$257.12	3.6%
2,300	$286.32	$295.33	3.1%
2,750	$343.47	$352.66	2.7%
3,000	$375.19	$384.49	2.5%
3,500	$438.71	$448.22	2.2%
4,000	$502.17	$511.87	1.9%
4,500	$565.69	$575.59	1.7%
5,000	$629.14	$639.25	1.6%
7,500	$946.61	$957.72	1.2%
10,000	$1,264.02	$1,276.13	1.0%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 1-phase Service

	Net Monthly Billing (without RPA credit)			Net Monthly Billing (with RPA credit)		
kWh	**Current Prices**	**Proposed Prices**	**Percent Difference**	**Current Prices**	**Proposed Prices**	**Percent Difference**
500	$73.40	$78.89	7.5%	$69.11	$74.59	7.9%
600	$84.58	$90.54	7.0%	$79.43	$85.38	7.5%
700	$95.76	$102.19	6.7%	$89.74	$96.17	7.2%
800	$106.92	$113.84	6.5%	$100.05	$106.96	6.9%
900	$118.12	$125.52	6.3%	$110.38	$117.78	6.7%
1,000	$129.28	$137.16	6.1%	$120.69	$128.56	6.5%
1,500	$185.17	$195.45	5.6%	$172.29	$182.55	6.0%
1,750	$213.12	$224.59	5.4%	$198.08	$209.55	5.8%
2,000	$241.05	$253.72	5.3%	$223.87	$236.52	5.7%
2,500	$296.94	$312.01	5.1%	$275.47	$290.50	5.5%
3,500	$408.71	$428.57	4.9%	$378.64	$398.46	5.2%
4,000	$464.58	$486.83	4.8%	$430.22	$452.43	5.2%
4,500	$520.48	$545.13	4.7%	$481.82	$506.42	5.1%
5,000	$576.35	$603.39	4.7%	$533.40	$560.39	5.1%
6,000	$654.26	$688.84	5.3%	$602.71	$637.24	5.7%
7,000	$732.16	$774.29	5.8%	$672.03	$714.09	6.3%
8,000	$810.06	$859.75	6.1%	$741.34	$790.94	6.7%
9,000	$887.96	$945.20	6.4%	$810.65	$867.79	7.0%
10,000	$965.86	$1,030.65	6.7%	$879.96	$944.65	7.4%
14,000	$1,277.47	$1,372.46	7.4%	$1,157.21	$1,252.05	8.2%
15,000	$1,355.38	$1,457.91	7.6%	$1,226.52	$1,328.90	8.3%
20,000	$1,744.89	$1,885.17	8.0%	$1,573.08	$1,713.16	8.9%
21,900	$1,892.92	$2,047.55	8.2%	$1,704.79	$1,859.20	9.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
500	$79.58	$88.16	10.8%	$75.29	$83.86	11.4%
600	$90.76	$99.81	10.0%	$85.61	$94.65	10.6%
700	$101.94	$111.46	9.3%	$95.92	$105.44	9.9%
800	$113.10	$123.11	8.9%	$106.23	$116.23	9.4%
900	$124.30	$134.79	8.4%	$116.56	$127.05	9.0%
1,000	$135.46	$146.43	8.1%	$126.87	$137.83	8.6%
1,500	$191.35	$204.72	7.0%	$178.47	$191.82	7.5%
1,750	$219.30	$233.86	6.6%	$204.26	$218.82	7.1%
2,000	$247.23	$262.99	6.4%	$230.05	$245.79	6.8%
2,500	$303.12	$321.28	6.0%	$281.65	$299.77	6.4%
3,500	$414.89	$437.84	5.5%	$384.82	$407.73	6.0%
4,000	$470.76	$496.10	5.4%	$436.40	$461.70	5.8%
4,500	$526.66	$554.40	5.3%	$488.00	$515.69	5.7%
5,000	$582.53	$612.66	5.2%	$539.58	$569.66	5.6%
6,000	$660.44	$698.11	5.7%	$608.89	$646.51	6.2%
7,000	$738.34	$783.56	6.1%	$678.21	$723.36	6.7%
8,000	$816.24	$869.02	6.5%	$747.52	$800.21	7.0%
9,000	$894.14	$954.47	6.7%	$816.83	$877.06	7.4%
10,000	$972.04	$1,039.92	7.0%	$886.14	$953.92	7.6%
14,000	$1,283.65	$1,381.73	7.6%	$1,163.39	$1,261.32	8.4%
15,000	$1,361.56	$1,467.18	7.8%	$1,232.70	$1,338.17	8.6%
20,000	$1,751.07	$1,894.44	8.2%	$1,579.26	$1,722.43	9.1%
21,900	$1,899.10	$2,056.82	8.3%	$1,710.97	$1,868.47	9.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 47 Summer Period

		Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
10	50	$45.82	$48.29	5.4%	$45.39	$47.86	5.4%
10	100	$55.61	$58.47	5.1%	$54.75	$57.60	5.2%
10	500	$133.81	$139.88	4.5%	$129.51	$135.58	4.7%
10	1,000	$221.20	$231.30	4.6%	$212.61	$222.70	4.7%
10	2,000	$396.04	$414.19	4.6%	$378.86	$396.99	4.8%
10	5,000	$920.56	$962.84	4.6%	$877.61	$919.84	4.8%
20	100	$55.61	$58.47	5.1%	$54.75	$57.60	5.2%
20	200	$75.13	$78.82	4.9%	$73.41	$77.10	5.0%
20	500	$133.81	$139.88	4.5%	$129.51	$135.58	4.7%
20	1,000	$231.49	$241.59	4.4%	$222.90	$232.99	4.5%
20	2,000	$406.33	$424.48	4.5%	$389.15	$407.28	4.7%
20	5,000	$930.85	$973.13	4.5%	$887.90	$930.13	4.8%
20	8,000	$1,455.36	$1,521.78	4.6%	$1,386.64	$1,452.97	4.8%
30	150	$65.37	$68.63	5.0%	$64.08	$67.34	5.1%
30	500	$133.81	$139.88	4.5%	$129.51	$135.58	4.7%
30	1,000	$231.49	$241.59	4.4%	$222.90	$232.99	4.5%
30	3,000	$591.48	$617.67	4.4%	$565.71	$591.87	4.6%
30	5,000	$941.16	$983.44	4.5%	$898.21	$940.44	4.7%
30	8,000	$1,465.67	$1,532.09	4.5%	$1,396.95	$1,463.28	4.7%
30	10,000	$1,815.35	$1,897.86	4.5%	$1,729.45	$1,811.85	4.8%
30	15,000	$2,689.55	$2,812.27	4.6%	$2,560.70	$2,683.27	4.8%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period

			Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
20%	35	5,110	$817.46	$835.88	2.3%	$773.56	$791.93	2.4%
40%	35	10,220	$1,557.62	$1,589.31	2.0%	$1,469.83	$1,501.41	2.1%
60%	35	15,330	$2,297.85	$2,342.79	2.0%	$2,166.16	$2,210.93	2.1%
80%	35	20,440	$3,038.05	$3,096.24	1.9%	$2,862.46	$2,920.45	2.0%
20%	50	7,300	$1,150.15	$1,174.24	2.1%	$1,087.45	$1,111.46	2.2%
40%	50	14,600	$2,207.56	$2,250.59	1.9%	$2,082.14	$2,125.02	2.1%
60%	50	21,900	$3,265.01	$3,326.99	1.9%	$3,076.88	$3,138.64	2.0%
80%	50	29,200	$4,322.41	$4,403.35	1.9%	$4,071.57	$4,152.21	2.0%
20%	70	10,220	$1,593.68	$1,625.36	2.0%	$1,505.89	$1,537.46	2.1%
40%	70	20,440	$3,074.11	$3,132.29	1.9%	$2,898.52	$2,956.50	2.0%
60%	70	30,660	$4,554.49	$4,639.23	1.9%	$4,291.12	$4,375.54	2.0%
80%	70	40,880	$6,034.88	$6,146.14	1.8%	$5,683.71	$5,794.55	2.0%
20%	100	14,600	$2,259.04	$2,302.09	1.9%	$2,133.63	$2,176.52	2.0%
40%	100	29,200	$4,373.90	$4,454.85	1.9%	$4,123.06	$4,203.71	2.0%
60%	100	43,800	$6,488.75	$6,607.59	1.8%	$6,112.51	$6,230.88	1.9%
80%	100	58,400	$8,603.61	$8,760.34	1.8%	$8,101.94	$8,258.08	1.9%
20%	200	29,200	$4,476.90	$4,557.85	1.8%	$4,226.06	$4,306.71	1.9%
40%	200	58,400	$8,706.61	$8,863.34	1.8%	$8,204.94	$8,361.08	1.9%
60%	200	87,600	$12,936.30	$13,168.82	1.8%	$12,183.80	$12,415.42	1.9%
80%	200	116,800	$17,166.01	$17,474.32	1.8%	$16,162.68	$16,469.78	1.9%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 51% on peak and 49% off peak energy consumption

	Net Monthly Bill (without RPA credit)			Net Monthly Bill (with RPA credit)		
kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
1,000	$163.68	$174.18	6.4%	$155.09	$165.58	6.8%
3,000	$439.55	$460.73	4.8%	$413.77	$434.93	5.1%
5,000	$715.41	$747.29	4.5%	$672.46	$704.28	4.7%
7,000	$991.27	$1,033.84	4.3%	$931.14	$973.64	4.6%
10,000	$1,405.07	$1,463.67	4.2%	$1,319.17	$1,377.67	4.4%
13,000	$1,818.86	$1,893.51	4.1%	$1,707.19	$1,781.70	4.4%
14,000	$1,956.79	$2,036.78	4.1%	$1,836.53	$1,916.38	4.3%
16,000	$2,232.66	$2,323.34	4.1%	$2,095.21	$2,185.73	4.3%
21,000	$2,922.32	$3,039.73	4.0%	$2,741.92	$2,859.11	4.3%
25,000	$3,474.04	$3,612.84	4.0%	$3,259.29	$3,397.82	4.3%
30,000	$4,163.70	$4,329.22	4.0%	$3,906.00	$4,071.21	4.2%
35,000	$4,853.36	$5,045.61	4.0%	$4,552.70	$4,744.59	4.2%
40,000	$5,543.02	$5,762.00	4.0%	$5,199.41	$5,417.98	4.2%
45,000	$6,232.68	$6,478.38	3.9%	$5,846.12	$6,091.36	4.2%
50,000	$6,922.34	$7,194.78	3.9%	$6,492.83	$6,764.76	4.2%
75,000	$10,370.63	$10,776.71	3.9%	$9,726.36	$10,131.67	4.2%
100,000	$13,818.92	$14,358.64	3.9%	$12,959.90	$13,498.59	4.2%
150,000	$20,715.51	$21,522.52	3.9%	$19,426.98	$20,232.45	4.1%
200,000	$27,612.09	$28,686.38	3.9%	$25,894.05	$26,966.28	4.1%
300,000	$41,405.26	$43,014.12	3.9%	$38,828.20	$40,433.97	4.1%
400,000	$55,198.43	$57,341.86	3.9%	$51,762.35	$53,901.66	4.1%
500,000	$68,991.60	$71,669.60	3.9%	$64,696.50	$67,369.35	4.1%
750,000	$99,597.48	$103,611.91	4.0%	$93,154.83	$97,161.54	4.3%
1,000,000	$132,788.05	$138,138.90	4.0%	$124,197.85	$129,538.40	4.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.
Bill comparison assumes 63% on peak and 37% off peak energy consumption

			Net Monthly Billing (without RPA credit)			Net Monthly Bill (with RPA credit)		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference	Current Prices	Proposed Prices	Percent Difference
30%	30	6,570	$725.11	$753.28	3.9%	$668.68	$696.78	4.2%
30%	50	10,950	$1,179.03	$1,222.55	3.7%	$1,084.97	$1,128.37	4.0%
30%	75	16,425	$1,746.41	$1,809.13	3.6%	$1,605.32	$1,667.86	3.9%
30%	100	21,900	$2,313.78	$2,395.67	3.5%	$2,125.65	$2,207.32	3.8%
30%	135	29,565	$3,108.04	$3,216.80	3.5%	$2,854.07	$2,962.52	3.8%
30%	175	38,325	$4,015.84	$4,155.30	3.5%	$3,686.62	$3,825.69	3.8%
30%	200	43,800	$4,583.21	$4,741.85	3.5%	$4,206.96	$4,365.15	3.8%
50%	30	10,950	$1,038.12	$1,079.38	4.0%	$944.06	$985.20	4.4%
50%	50	18,250	$1,700.69	$1,766.02	3.8%	$1,543.91	$1,609.06	4.2%
50%	75	27,375	$2,528.87	$2,624.29	3.8%	$2,293.71	$2,388.85	4.1%
50%	100	36,500	$3,357.06	$3,482.57	3.7%	$3,043.52	$3,168.64	4.1%
50%	135	49,275	$4,516.53	$4,684.16	3.7%	$4,093.25	$4,260.37	4.1%
50%	175	63,875	$5,841.63	$6,057.41	3.7%	$5,292.93	$5,508.05	4.1%
50%	200	73,000	$6,669.82	$6,915.68	3.7%	$6,042.73	$6,287.84	4.1%
70%	30	15,330	$1,351.08	$1,405.42	4.0%	$1,219.40	$1,273.57	4.4%
70%	50	25,550	$2,222.34	$2,309.47	3.9%	$2,002.85	$2,089.73	4.3%
70%	75	38,325	$3,311.32	$3,439.45	3.9%	$2,982.10	$3,109.84	4.3%
70%	100	51,100	$4,400.34	$4,569.47	3.8%	$3,961.38	$4,129.97	4.3%
70%	135	68,985	$5,924.96	$6,151.46	3.8%	$5,332.37	$5,558.16	4.2%
70%	175	89,425	$7,667.42	$7,959.50	3.8%	$6,899.24	$7,190.40	4.2%
70%	200	102,200	$8,756.41	$9,089.50	3.8%	$7,878.49	$8,210.53	4.2%
90%	30	19,710	$1,664.09	$1,731.52	4.1%	$1,494.78	$1,562.00	4.5%
90%	50	32,850	$2,743.97	$2,852.91	4.0%	$2,461.78	$2,570.38	4.4%
90%	75	49,275	$4,093.82	$4,254.65	3.9%	$3,670.54	$3,830.86	4.4%
90%	100	65,700	$5,443.64	$5,656.38	3.9%	$4,879.26	$5,091.32	4.3%
90%	135	88,695	$7,333.41	$7,618.79	3.9%	$6,571.50	$6,855.97	4.3%
90%	175	114,975	$9,493.17	$9,861.57	3.9%	$8,505.51	$8,872.73	4.3%
90%	200	131,400	$10,843.00	$11,263.29	3.9%	$9,714.25	$10,133.19	4.3%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Secondary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,690.18	$4,825.72	2.9%
30%	300	65,700	$6,685.04	$6,811.13	1.9%
30%	500	109,500	$10,674.82	$10,781.97	1.0%
30%	700	153,300	$14,664.61	$14,752.81	0.6%
30%	800	175,200	$16,659.49	$16,738.23	0.5%
30%	900	197,100	$18,654.35	$18,723.62	0.4%
30%	1,000	219,000	$20,649.26	$20,709.06	0.3%
30%	1,500	328,500	$30,623.69	$30,636.12	0.0%
30%	2,000	438,000	$40,598.13	$40,563.21	-0.1%
30%	4,000	876,000	$77,728.75	$77,504.41	-0.3%
50%	200	73,000	$6,550.74	$6,714.87	2.5%
50%	300	109,500	$9,475.90	$9,644.85	1.8%
50%	500	182,500	$15,326.25	$15,504.82	1.2%
50%	700	255,500	$21,176.59	$21,364.79	0.9%
50%	800	292,000	$24,101.77	$24,294.79	0.8%
50%	900	328,500	$27,026.93	$27,224.76	0.7%
50%	1,000	365,000	$29,952.11	$30,154.76	0.7%
50%	1,500	547,500	$44,577.95	$44,804.68	0.5%
50%	2,000	730,000	$59,203.81	$59,454.62	0.4%
50%	4,000	1,460,000	$112,865.38	$113,212.49	0.3%
70%	200	102,200	$8,411.31	$8,604.02	2.3%
70%	300	153,300	$12,266.77	$12,478.57	1.7%
70%	500	255,500	$19,977.67	$20,227.67	1.3%
70%	700	357,700	$27,688.58	$27,976.79	1.0%
70%	800	408,800	$31,544.04	$31,851.34	1.0%
70%	900	459,900	$35,399.51	$35,725.93	0.9%
70%	1,000	511,000	$39,254.95	$39,600.46	0.9%
70%	1,500	766,500	$56,110.99	$56,552.01	0.8%
70%	2,000	1,022,000	$74,570.20	$75,106.73	0.7%
70%	4,000	2,044,000	$147,940.01	$148,858.56	0.6%
90%	200	131,400	$10,271.90	$10,493.17	2.2%
90%	300	197,100	$15,057.59	$15,312.26	1.7%
90%	500	328,500	$24,629.09	$24,950.52	1.3%
90%	700	459,900	$34,200.59	$34,588.81	1.1%
90%	800	525,600	$38,986.30	$39,407.90	1.1%
90%	900	591,300	$43,772.06	$44,227.03	1.0%
90%	1,000	657,000	$48,557.79	$49,046.17	1.0%
90%	1,500	985,500	$69,373.49	$70,028.79	0.9%
90%	2,000	1,314,000	$92,107.52	$92,929.77	0.9%
90%	4,000	2,628,000	$183,014.64	$184,504.64	0.8%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 85, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	200	43,800	$4,537.10	$4,636.73	2.2%
30%	300	65,700	$6,470.89	$6,579.15	1.7%
30%	500	109,500	$10,338.48	$10,463.98	1.2%
30%	700	153,300	$14,206.08	$14,348.81	1.0%
30%	800	175,200	$16,139.89	$16,291.23	0.9%
30%	900	197,100	$18,073.66	$18,233.62	0.9%
30%	1,000	219,000	$20,007.48	$20,176.06	0.8%
30%	1,500	328,500	$29,676.46	$29,888.14	0.7%
30%	2,000	438,000	$39,345.46	$39,600.22	0.6%
30%	4,000	876,000	$75,254.32	$75,681.44	0.6%
50%	200	73,000	$6,364.28	$6,491.89	2.0%
50%	300	109,500	$9,211.66	$9,361.88	1.6%
50%	500	182,500	$14,906.45	$15,101.86	1.3%
50%	700	255,500	$20,601.23	$20,841.85	1.2%
50%	800	292,000	$23,448.62	$23,711.85	1.1%
50%	900	328,500	$26,296.00	$26,581.84	1.1%
50%	1,000	365,000	$29,143.40	$29,451.84	1.1%
50%	1,500	547,500	$43,380.35	$43,801.80	1.0%
50%	2,000	730,000	$57,617.30	$58,151.77	0.9%
50%	4,000	1,460,000	$109,723.26	$110,709.79	0.9%
70%	200	102,200	$8,191.46	$8,347.04	1.9%
70%	300	153,300	$11,952.44	$12,144.61	1.6%
70%	500	255,500	$19,474.41	$19,739.75	1.4%
70%	700	357,700	$26,996.37	$27,334.89	1.3%
70%	800	408,800	$30,757.36	$31,132.47	1.2%
70%	900	459,900	$34,518.35	$34,930.06	1.2%
70%	1,000	511,000	$38,279.32	$38,727.61	1.2%
70%	1,500	766,500	$54,663.01	$55,294.24	1.2%
70%	2,000	1,022,000	$72,649.85	$73,464.03	1.1%
70%	4,000	2,044,000	$144,130.20	$145,676.15	1.1%
90%	200	131,400	$10,018.65	$10,202.21	1.8%
90%	300	197,100	$14,693.20	$14,927.32	1.6%
90%	500	328,500	$24,042.36	$24,377.64	1.4%
90%	700	459,900	$33,391.53	$33,827.96	1.3%
90%	800	525,600	$38,066.09	$38,553.07	1.3%
90%	900	591,300	$42,740.66	$43,278.23	1.3%
90%	1,000	657,000	$47,415.24	$48,003.38	1.2%
90%	1,500	985,500	$67,675.12	$68,516.12	1.2%
90%	2,000	1,314,000	$89,853.32	$90,947.20	1.2%
90%	4,000	2,628,000	$178,537.15	$180,642.51	1.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill Current Prices	Net Monthly Bill Proposed Prices	Percent Difference
30%	4,000	876,000	$74,148.01	$75,801.08	2.2%
30%	7,500	1,642,500	$134,740.79	$137,497.81	2.0%
30%	10,000	2,190,000	$177,977.03	$181,522.60	2.0%
30%	15,000	3,285,000	$264,449.55	$269,572.20	1.9%
30%	20,000	4,380,000	$350,922.07	$357,621.81	1.9%
50%	4,000	1,460,000	$107,666.56	$110,023.40	2.2%
50%	7,500	2,737,500	$197,471.80	$201,548.41	2.1%
50%	10,000	3,650,000	$261,618.39	$266,923.41	2.0%
50%	15,000	5,475,000	$389,911.59	$397,673.41	2.0%
50%	20,000	7,300,000	$518,204.78	$528,423.41	2.0%
70%	4,000	2,044,000	$141,123.10	$144,183.72	2.2%
70%	7,500	3,832,500	$260,202.82	$265,599.01	2.1%
70%	10,000	5,110,000	$345,259.75	$352,324.21	2.0%
70%	15,000	7,665,000	$515,373.62	$525,774.61	2.0%
70%	20,000	10,220,000	$685,487.49	$699,225.01	2.0%
90%	4,000	2,628,000	$174,579.64	$178,344.04	2.2%
90%	7,500	4,927,500	$322,933.84	$329,649.61	2.1%
90%	10,000	6,570,000	$428,901.10	$437,725.01	2.1%
90%	15,000	9,855,000	$640,835.65	$653,875.81	2.0%
90%	20,000	13,140,000	$852,770.20	$870,026.62	2.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
30%	4,000	876,000	$71,228.21	$72,740.91	2.1%
30%	7,500	1,642,500	$130,518.90	$133,111.87	2.0%
30%	10,000	2,190,000	$172,825.08	$176,189.68	1.9%
30%	15,000	3,285,000	$257,437.47	$262,345.31	1.9%
30%	20,000	4,380,000	$342,049.85	$348,500.95	1.9%
50%	4,000	1,460,000	$104,139.22	$106,337.65	2.1%
50%	7,500	2,737,500	$192,110.79	$195,989.51	2.0%
50%	10,000	3,650,000	$254,947.60	$260,026.53	2.0%
50%	15,000	5,475,000	$380,621.24	$388,100.59	2.0%
50%	20,000	7,300,000	$506,294.89	$516,174.65	2.0%
70%	4,000	2,044,000	$136,988.23	$139,872.39	2.1%
70%	7,500	3,832,500	$253,702.68	$258,867.15	2.0%
70%	10,000	5,110,000	$337,070.11	$343,863.38	2.0%
70%	15,000	7,665,000	$503,805.02	$513,855.86	2.0%
70%	20,000	10,220,000	$670,539.93	$683,848.35	2.0%
90%	4,000	2,628,000	$169,837.23	$173,407.13	2.1%
90%	7,500	4,927,500	$315,294.56	$321,744.78	2.0%
90%	10,000	6,570,000	$419,192.63	$427,700.23	2.0%
90%	15,000	9,855,000	$626,988.80	$639,611.14	2.0%
90%	20,000	13,140,000	$834,784.96	$851,522.05	2.0%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Load Factor	kW	kWh	Net Monthly Bill: Current Prices	Net Monthly Bill: Proposed Prices	Percent Difference
30%	4,000	876,000	$67,122.88	$68,904.65	2.7%
30%	5,000	1,095,000	$82,545.42	$84,685.09	2.6%
30%	10,000	2,190,000	$159,348.15	$163,277.29	2.5%
30%	20,000	4,380,000	$312,953.59	$320,461.67	2.4%
30%	40,000	8,760,000	$620,164.48	$634,830.44	2.4%
30%	50,000	10,950,000	$773,769.93	$792,014.83	2.4%
30%	70,000	15,330,000	$1,080,980.82	$1,106,383.60	2.3%
50%	4,000	1,460,000	$99,576.73	$102,038.22	2.5%
50%	5,000	1,825,000	$123,035.24	$126,024.56	2.4%
50%	10,000	3,650,000	$240,327.78	$245,956.21	2.3%
50%	20,000	7,300,000	$474,912.85	$485,819.52	2.3%
50%	40,000	14,600,000	$944,083.00	$965,546.14	2.3%
50%	50,000	18,250,000	$1,178,668.08	$1,205,409.45	2.3%
50%	70,000	25,550,000	$1,647,838.23	$1,685,136.07	2.3%
70%	4,000	2,044,000	$131,968.58	$135,109.79	2.4%
70%	5,000	2,555,000	$163,525.05	$167,364.02	2.3%
70%	10,000	5,110,000	$321,307.41	$328,635.13	2.3%
70%	20,000	10,220,000	$636,872.11	$651,177.37	2.2%
70%	40,000	20,440,000	$1,268,001.52	$1,296,261.84	2.2%
70%	50,000	25,550,000	$1,583,566.23	$1,618,804.07	2.2%
70%	70,000	35,770,000	$2,214,695.64	$2,263,888.54	2.2%
90%	4,000	2,628,000	$164,360.43	$168,181.36	2.3%
90%	5,000	3,285,000	$204,014.87	$208,703.48	2.3%
90%	10,000	6,570,000	$402,287.04	$411,314.06	2.2%
90%	20,000	13,140,000	$798,831.37	$816,535.22	2.2%
90%	40,000	26,280,000	$1,591,920.04	$1,626,977.53	2.2%
90%	50,000	32,850,000	$1,988,464.38	$2,032,198.69	2.2%
90%	70,000	45,990,000	$2,781,553.05	$2,842,641.01	2.2%

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 90, Primary, 3 phase service.
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices	Proposed Prices	Percent Difference
80%	4,000	2,336,000	$151,792.99	$156,881.36	3.4%
80%	5,000	2,920,000	$187,741.64	$193,957.90	3.3%
80%	10,000	5,840,000	$367,484.88	$379,340.59	3.2%
80%	20,000	11,680,000	$726,971.36	$750,105.98	3.2%
80%	40,000	23,360,000	$1,445,944.32	$1,491,636.77	3.2%
80%	60,000	35,040,000	$2,164,917.28	$2,233,167.55	3.2%
80%	80,000	46,720,000	$2,883,890.24	$2,974,698.34	3.1%
90%	4,000	2,628,000	$167,552.82	$173,035.18	3.3%
90%	5,000	3,285,000	$207,441.42	$214,150.17	3.2%
90%	10,000	6,570,000	$406,884.44	$419,725.14	3.2%
90%	20,000	13,140,000	$805,770.48	$830,875.08	3.1%
90%	40,000	26,280,000	$1,603,542.56	$1,653,174.96	3.1%
90%	60,000	39,420,000	$2,401,314.64	$2,475,474.85	3.1%
90%	80,000	52,560,000	$3,199,086.72	$3,297,774.73	3.1%

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2019 COSTS TO RATE SCHEDULES ($000)

	Energy-Based Charges					Trans. & Related Charges			Distribution Demand & Facilities Charges				
Grouping	Power Supply	Franchise Fees	Trojan	Sch 129	Subtotal	Transmission	Ancillary Services	Subtotal	Substation	Subtrans.	Feeder Backbone	Feeder Facilities	Subtotal
Schedule 7	$505,920	$25,272	$1,081	($7,159)	$19,194	$16,629	$2,300	$18,929	$35,443	$35,692	$59,100	$90,151	$220,386
Schedule 15	$809	$86	$2	($15)	$73	$21	$4	$24	$70	$70	$122	$119	$381
Schedule 32	$96,551	$4,887	$206	($1,518)	$3,575	$2,927	$439	$3,366	$5,555	$5,594	$11,210	$18,412	$40,770
Schedule 38	$1,722	$108	$4	($29)	$82	$45	$8	$53	$235	$237	$471	$830	$1,773
Schedule 47	$1,524	$113	$3	($21)	$95	$40	$7	$47	$228	$230	$461	$797	$1,717
Schedule 49	$4,569	$243	$10	($62)	$191	$121	$21	$142	$642	$646	$1,286	$1,271	$3,845
Schedule 83													
Secondary	$166,493	$6,621	$356	($2,628)	$4,349	$5,195	$758	$5,953	$10,261	$10,333	$20,572	$17,200	$58,365
Schedule 85													
Secondary		$4,768	$342	($2,618)	$2,492								
Primary		$1,376	$110	($863)	$623								
Class Total	$160,737					$4,839	$731	$5,570	$11,872	$11,955	$18,952	$9,238	$52,018
Schedule 89													
Secondary		$6	$2	($13)	($5)						$110		$110
Primary		$1,186	$156	($1,296)	$46						$2,969		$2,969
Subtransmission		$172	$26	($217)	($19)						$664		$664
Class Total	$28,487					$1,092	$186	$1,278	$3,747	$4,495			$8,243
Schedule 90-P	$91,678	$2,688	$196	($1,678)	$1,206	$2,150	$366	$2,516	$3,818	$3,698	$2,096		$9,613
Schedules 91 & 95	$2,769	$294	$6	($51)	$249	$70	$13	$83	$239	$241	$418	$452	$1,350
Schedules 92	$133	$5	$0	($2)	$3	$3	$1	$4	$5	$5	$9	$4	$24
Totals	$1,061,392	$47,823	$2,500	($18,170)	$32,153	$33,134	$4,832	$37,966	$72,114	$73,197	$118,440	$138,474	$402,226

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2019 COSTS TO RATE SCHEDULES ($000)

	Dist. Customer-Related TSM		Uncollectibles		Metering		Billing		Other Consumer		Subtotal				Total
Grouping	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal	Cost Allocations
Schedule 7	$115,921	$37	$5,986	$1	$7,183	$1	$62,384	$10	$42,900	$7	$234,375	$57		$234,432	$998,861
Schedule 15	$199		$53		$0		$137		$107		$495	$0	$1,614	$2,109	$3,397
Schedule 32	$13,477	$16,692	$182	$122	$1,148	$769	$3,800	$2,545	$5,998	$4,017	$24,605	$24,144		$48,750	$193,013
Schedule 38	$20	$344	$0	$0	$18	$113	$5	$28	$14	$84	$57	$570		$627	$4,257
Schedule 47	$21	$436	$0	$6	$7	$88	$15	$191	$22	$289	$66	$1,009		$1,075	$4,458
Schedule 49	$2	$403	$0	$6	$0	$45	$1	$97	$2	$324	$5	$875		$880	$9,627
Schedule 83															
Secondary	$423	$18,105	$4	$68	$50	$815	$56	$910	$310	$5,020	$844	$24,917		$25,762	$260,922
Schedule 85															
Secondary		$5,268		$32		$503		$243		$3,961	$0	$10,007		$10,007	
Primary		$619		$5		$85		$41		$665	$0	$1,415		$1,415	$232,860
Schedule 89															
Secondary		$21		$0		$0		$0		$21	$0	$42		$42	
Primary		$70		$0		$1		$10		$580	$0	$662		$662	
Subtransmission		$170		$0		$0		$2		$129	$0	$302		$302	$42,777
Schedule 90-P		$10		$0		$0		$0		$306	$0	$317		$317	$105,330
Schedules 91 & 95	$1,515			$0		$0	$409		$2		$1,927	$0	$5,267	$7,194	$11,644
Schedule 92		$16		$0		$0		$34		$0	$0	$51		$51	$215
Totals	$131,579	$42,191	$6,225	$240	$8,407	$2,420	$66,807	$4,112	$49,356	$15,404	$262,374	$64,368	$6,881	$333,623	$1,867,360

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2019

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 7						
Residential						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$234,375	781,021	Customers	$25.01	per cust. per mo.	$234,400
Three-Phase	$57	130	Customers	$36.39	per cust. per mo.	$57
Trans. & Rel. Serv. Charge	$18,929	7,502,509	MWh	2.52	mills/kWh	$18,906
Distribution Charge	$220,386	7,502,509	MWh	29.37	mills/kWh	$220,349
Franchise Fees & Other	$19,194	7,502,509	MWh	2.56	mills/kWh	$19,206
Energy Charge	$505,920	7,502,509	MWh	67.43	mills/kWh	$505,894
Subtotal	$998,861					$998,813
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		781,021	Customers	$13.00	per cust. per mo.	$121,839
Three-Phase		130	Customers	$13.00	per cust. per mo.	$20
Trans. & Rel. Serv. Charge		7,502,509	MWh	2.52	mills/kWh	$18,906
Distribution Charge		7,502,509	MWh	44.38	mills/kWh	$332,961
System Usage Charge Calculation						
Franchise Fees & Other		7,502,509	MWh	2.56	mills/kWh	$19,206
Cust Impact Offset		7,502,509	MWh	(0.09)	mills/kWh	($675)
System Usage Charge		7,502,509	MWh	2.47	mills/kWh	$18,531
Energy Charge						
Block 1 (First 500 kWh)		4,147,717	MWh	66.27	mills/kWh	$274,869
Block 2 (501-1,000 kWh)		2,149,972	MWh	66.27	mills/kWh	$142,479
Block 3 (Over 1,000 kWh)		1,204,821	MWh	73.49	mills/kWh	$88,542
Subtotal						$998,149
					w/o CIO	$998,824
SCHEDULE 15						
Outdoor Area Lighting						
Allocations						
Functional Costs						
Basic Charge	$495	9,486	Customers	$4.35	per cust. per mo.	$495
Trans. & Rel. Serv. Charge	$24	15,630	MWh	1.55	mills/kWh	$24
Distribution Charge	$381	15,630	MWh	24.40	mills/kWh	$381
Franchise Fees & Other	$73	15,630	MWh	4.64	mills/kWh	$73
Energy Charge	$809	15,630	MWh	51.77	mills/kWh	$809
Fixed Charges	$1,614	15,630	MWh			$1,614
Subtotal	$3,397					$3,397
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		15,630	MWh	1.55	mills/kWh	$24
Distribution Charge		15,630	MWh	56.08	mills/kWh	$877
System Usage Charge Calc						
Franchise Fees & Other		15,630	MWh	4.64	mills/kWh	$73
Cust Impact Offset		15,630	MWh	4.03	mills/kWh	$63
System Usage Charge		15,630	MWh	8.67	mills/kWh	$136
Energy Charge		15,630	MWh	51.77	mills/kWh	$809
Fixed Charges		15,630	MWh			$1,614
Subtotal						$3,460
					w/o CIO	$3,397

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$24,605	56,092	Customers	$36.56	per cust. per mo.	$24,609
Three-Phase	$24,144	37,563	Customers	$53.56	per cust. per mo.	$24,143
Trans. & Rel. Serv. Charge	$3,366	1,590,863	MWh	2.12	mills/kWh	$3,373
Distribution Charge	$40,770	1,590,863	MWh	25.63	mills/kWh	$40,774
Franchise Fees & Other	$3,575	1,590,863	MWh	2.25	mills/kWh	$3,579
Energy Charge	$96,551	1,590,863	MWh	60.69	mills/kWh	$96,549
Subtotal	$193,013					$193,027
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		56,092	Customers	$20.00	per cust. per mo.	$13,462
Three-Phase		37,563	Customers	$29.00	per cust. per mo.	$13,072
Trans. & Rel. Serv. Charge		1,590,863	MWh	2.12	mills/kWh	$3,373
Distribution Charge						
First 5 MWh		1,396,287	MWh	43.29	mills/kWh	$60,445
Over 5 MWh		194,576	MWh	13.00	mills/kWh	$2,529
System Usage Charge Calc						
Franchise Fees & Other		1,590,863	MWh	2.25	mills/kWh	$3,579
Cust Impact Offset		1,590,863	MWh	(0.09)	mills/kWh	($143)
System Usage Charge		1,590,863	MWh	2.16	mills/kWh	$3,436
Energy Charge		1,590,863	MWh	60.69	mills/kWh	$96,549
Subtotal						$192,867
					w/o CIO	$193,011
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$57	55	Customers	$86.26	per cust. per mo.	$57
Three-Phase	$570	337	Customers	$140.92	per cust. per mo.	$570
Trans. & Rel. Serv. Charge	$53	30,626	MWh	1.74	per cust. per mo.	$53
Distribution Charges	$1,773	30,626	MWh	57.88	per cust. per mo.	$1,773
Franchise Fees & Other	$82	30,626	MWh	2.68	mills/kWh	$82
Energy Charge	$1,722	30,626	MWh	56.22	mills/kWh	$1,722
Subtotal	$4,257					$4,257
Pricing						
Functional Costs						
Basic						
Single-Phase		55	Customers	$30.00	per cust. per mo.	$20
Three-Phase		337	Customers	$30.00	per cust. per mo.	$121
Trans. & Rel. Serv. Charge		30,626	MWh	1.74	mills/kWh	$53
Distribution Charges		30,626	MWh	72.81	mills/kWh	$2,230
System Usage Charge						
Franchise Fees & Other		30,626	MWh	2.68	mills/kWh	$82
Cust Impact Offset		30,626	MWh	0.00	mills/kWh	$0
System Usage Charge		30,626	MWh	2.68	mills/kWh	$82
Energy Charge Calc						
On-Peak (special)		16,832	MWh	62.97	mills/kWh	$1,060
Off-Peak		13,794	MWh	47.97	mills/kWh	$662
Reactive Demand Charge		57,689	kVar	0.50	kVar	$29
Subtotal						$4,257
					w/o CIO	$4,257

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase	$66	218	Customers	$50.33	per cust. per summ. mo.	$66
Three-Phase	$1,009	2,813	Customers	$59.77	per cust. per summ. mo.	$1,009
Trans. & Rel. Serv. Charge	$47	21,544	MWh	2.18	mills/kWh	$47
Distribution Charges	$1,717	21,544	MWh	79.70	mills/kWh	$1,717
Franchise Fees & Other	$95	21,544	MWh	4.42	mills/kWh	$95
Energy Charge	$1,524	21,544	MWh	70.75	mills/kWh	$1,524
Subtotal	$4,458					$4,458
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		218	Customers	$37.00	per cust. per summ. mo.	$48
Three-Phase		2,813	Customers	$37.00	per cust. per summ. mo.	$624
Trans. & Rel. Serv. Charge		21,544	MWh	2.18	mills/kWh	$47
Distribution Charge Calc						
First 50 kWh per kW		7,764	MWh	111.13	mills/kWh	$863
Over 50 kWh per kW		13,780	MWh	91.13	mills/kWh	$1,256
System Usage Charge Calc						
Franchise Fees & Other		21,544	MWh	4.42	mills/kWh	$95
Cust Impact Offset		21,544	MWh	0.00	mills/kWh	$0
System Usage Charge		21,544	MWh	4.42	mills/kWh	$95
Energy Charge		21,544	MWh	70.75	mills/kWh	$1,524
Reactive Demand Charge		68	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$4,458
					w/o CIO	$4,458
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Allocations						
Functional Costs						
Basic						
Single-Phase	$5	7	Customers	$109.29	per cust. per summ. mo.	$5
Three-Phase	$875	1,297	Customers	$112.47	per cust. per summ. mo.	$875
Trans. & Rel. Serv. Charge	$142	64,947	MWh	2.19	mills/kWh	$142
Distribution Charges	$3,845	64,947	MWh	59.20	mills/kWh	$3,845
Franchise Fees & Other	$191	64,947	MWh	2.94	mills/kWh	$191
Energy Charge	$4,569	64,947	MWh	70.35	mills/kWh	$4,569
Subtotal	$9,627					$9,627
Pricing						
Functional Costs						
Basic Charge						
Single-Phase		7	Customers	$45.00	per cust. per summ. mo.	$2
Three-Phase		1,297	Customers	$45.00	per cust. per summ. mo.	$350
Trans. & Rel. Serv. Charge		64,947	MWh	2.19	mills/kWh	$142
Distribution Charge Calc						
First 50 kWh per kW		19,766	MWh	81.18	mills/kWh	$1,605
Over 50 kWh per kW		45,181	MWh	61.18	mills/kWh	$2,764
System Usage Charge Calc						
Franchise Fees & Other		64,947	MWh	2.94	mills/kWh	$191
Cust Impact Offset		64,947	MWh	0.00	mills/kWh	$0
System Usage Charge		64,947	MWh	2.94	mills/kWh	$191
Energy Charge		64,947	MWh	70.35	mills/kWh	$4,569
Reactive Demand Charge		6,858	kVar	0.50	kVar	$3
Subtotal with Consumer Impact Offset						$9,627
					w/o CIO	$9,627

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-200 kW						
Allocations						
Functional Costs						
Basic Charge						
Single-Phase Secondary	$844	661	Customers	$106.45	per cust, per mo.	$844
Three-Phase Secondary	$24,917	10,688	Customers	$194.28	per cust, per mo.	$24,917
Transmission & Related Service Charge	$5,953	8,392,038	kW demand	$0.71	per kW demand	$5,958
Distribution Charges						
Feeder Backbone	$20,572	10,668,799	kW faccap	$1.93	per kW faccap	$20,591
Feeder Local Facilities	$17,200	10,668,799	kW faccap	$1.61	per kW faccap	$17,177
Subtransmission Charge	$10,333	8,392,038	kW demand	$1.23	per kW demand	$10,322
Substation Charge	$10,261	8,392,038	kW demand	$1.22	per kW demand	$10,238
Secondary Franchise Fees & Other	$4,349	2,753,722	MWh	1.58	mills/kWh	$4,351
Secondary COS Energy Charge	$166,493	2,753,722	MWh	60.46	mills/kWh	$166,490
Subtotal	$260,922					$260,889
Pricing						
Functional Costs						
Basic Charge						
Secondary Single-Phase		661	Customers	$35.00	per cust, per mo.	$278
Secondary Three-Phase		10,688	Customers	$45.00	per cust, per mo.	$5,771
Trans. & Rel. Serv. Charge						
On-peak		8,388,757	kW demand	$0.79	per kW demand	$6,627
Off-peak		3,281	kW demand	$0.00	per kW demand	$0
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,085,550	kW faccap	$3.60	<= 30 kW faccap	$14,708
Over 30 kW		6,583,249	kW faccap	$3.50	> 30 kW faccap	$23,041
Secondary Demand Charge						
On-peak		8,388,757	kW demand	$2.66	per kW demand	$22,314
Off-peak		3,281	kW demand	$0.00	per kW demand	$0
Secondary System Usage Charge Calc						
Franchise Fees & Other		2,753,722	MWh	1.58	mills/kWh	$4,351
Cust Impact Offset		2,753,722	MWh	0.00	mills/kWh	$0
Rate Design		2,753,722	MWh	6.20	mills/kWh	$17,073
System Usage Charge		2,753,722	MWh	7.78	mills/kWh	$21,424
COS Energy Charge						
On-peak		1,833,432	MWh	65.47	mills/kWh	$120,035
Off-peak		920,290	MWh	50.47	mills/kWh	$46,447
Reactive Demand Charge		544,161	kVar	$0.50	kVar	$272
Subtotal						$260,917
					w/o CIO	$260,917

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 85						
General Service 201-4,000 kW						
Allocations						
Functional Costs						
Basic Charge						
Secondary	$10,007	1,421	Customers	$586.73	per cust, per mo.	$10,007
Primary	$1,415	239	Customers	$493.82	per cust, per mo.	$1,415
Transmission & Related Service Charge	$5,570	7,301,074	kW on-peak	$0.76	per kW demand	$5,549
Distribution Charges						
Feeder Backbone	$18,952	10,846,368	kW faccap	$1.75	per kW faccap	$18,981
Feeder Local Facilities	$9,238	10,846,368	kW faccap	$0.85	per kW faccap	$9,219
Subtransmission Charge	$11,955	9,103,824	kW on-peak	$1.31	per kW on-peak demand	$11,926
Substation Charge	$11,872	9,103,824	kW on-peak	$1.30	per kW on-peak demand	$11,835
Secondary Franchise Fees & Other	$2,492	2,743,509	MWh	0.91	mills/kWh	$2,497
Primary Franchise Fees & Other	$623	904,314	MWh	0.69	mills/kWh	$624
COS Energy Charge	$160,737	2,766,237	MWh	58.11	mills/kWh	$160,746
Subtotal	$232,860					$232,799
Pricing						
Functional Costs						
Basic Charge						
Secondary		1,421	Customers	$590.00	per cust, per mo.	$10,063
Primary		239	Customers	$490.00	per cust, per mo.	$1,404
Secondary Trans. & Rel. Serv. Charge		5,809,281	kW on-peak	$0.79	per kW demand	$4,589
Primary Trans. & Rel. Serv. Charge		1,491,793	kW on-peak	$0.77	per kW demand	$1,149
Distribution Charges						
Secondary Facilities Charge						
First 200 kW		3,411,200	kW faccap	$3.27	per kW faccap	$11,155
Over 200 kW		4,881,912	kW faccap	$2.07	per kW faccap	$10,106
Primary Facilities Charge						
First 200 kW		573,000	kW faccap	$3.20	per kW faccap	$1,834
Over 200 kW		1,980,256	kW faccap	$2.00	per kW faccap	$3,961
Secondary Demand Charge		6,965,700	kW on-peak	$2.66	per kW demand	$18,529
Primary Demand Charge		2,138,124	kW on-peak	$2.58	per kW demand	$5,516
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		2,178,260	MWh	1.18	mills/kWh	$2,570
Cust Impact Offset		2,178,260	MWh	0.00	mills/kWh	$0
COS System Usage Charge		2,178,260	MWh	1.18	mills/kWh	$2,570
DA Franchise Fees & Other		565,248	MWh	(0.14)	mills/kWh	($79)
Cust Impact Offset		565,248	MWh	0.00	mills/kWh	$0
DA System Usage Charge		565,248	MWh	(0.14)	mills/kWh	($79)
Primary System Usage Charge Calc						
COS Franchise Fees & Other		587,976	MWh	1.14	mills/kWh	$670
Cust Impact Offset		587,976	MWh	0.00	mills/kWh	$0
COS System Usage Charge		587,976	MWh	1.14	mills/kWh	$670
DA Franchise Fees & Other		316,338	MWh	(0.15)	mills/kWh	($47)
Cust Impact Offset		316,338	MWh	0.00	mills/kWh	$0
DA System Usage Charge		316,338	MWh	(0.15)	mills/kWh	($47)
Secondary COS Energy Charge						
On-peak		1,429,075	MWh	63.58	mills/kWh	$90,861
Off-peak		749,185	MWh	48.58	mills/kWh	$36,395
Primary COS Energy Charge						
On-peak		370,985	MWh	62.50	mills/kWh	$23,187
Off-peak		216,991	MWh	47.50	mills/kWh	$10,307
Reactive Demand Charge		1,394,441	kVar	0.50	kVar	$697
Subtotal						$232,865
					w/o CIO	$232,865

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SCHEDULE 89 GT 4,000 kW						
General Service						
Allocations						
Functional Costs						
Secondary Basic Charge	$42	1	Customers	$3,536.54	per cust, per mo.	$42
Primary Basic Charge	$662	27	Customers	$2,042.39	per cust, per mo.	$662
Subtransmission Basic Charge	$302	6	Customers	$4,191.39	per cust, per mo.	$302
Transmission & Related Service Charge	$1,278	1,305,583	kW on-peak	$0.98	per kW on-peak demand	$1,279
Distribution Charges						
Feeder Backbone	$3,743	3,546,134	kW faccap	$1.06	per kW faccap	$3,759
Feeder Local Facilities						$0
Subtransmission Demand Charge	$4,495	3,125,604	kW on-peak	$1.44	per kW on-peak demand	$4,501
Substation Demand Charge	$3,747	2,523,544	kW on-peak	$1.48	per kW on-peak demand	$3,735
Secondary Franchise Fees & Other	($5)	13,399	MWh	(0.38)	mills/kWh	($5)
Primary Franchise Fees & Other	$46	1,358,012	MWh	0.03	mills/kWh	$41
Subtransmission Franchise Fees & Other	($19)	227,004	MWh	(0.08)	mills/kWh	($18)
Energy Charge	$28,487	527,311	MWh	54.02	mills/kWh	$28,485
Subtotal	$42,777					$42,783
Pricing						
Functional Costs						
Secondary Basic Charge		1	Customers	$3,540.00	per cust, per mo.	$42
Primary Basic Charge		27	Customers	$2,040.00	per cust, per mo.	$661
Subtransmission Basic Charge		6	Customers	$4,190.00	per cust, per mo.	$302
Secondary Trans. & Rel. Serv. Charge		0	kW on-peak	$0.79	per kW on-peak demand	$0
Primary Trans. & Rel. Serv. Charge		1,042,580	kW on-peak	$0.77	per kW on-peak demand	$803
Subtransmission Trans. & Rel. Serv. Charge		263,003	kW on-peak	$0.76	per kW on-peak demand	$200
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		12,000	kW faccap	$1.52	per kW faccap	$18
1,001-4,000 kW		36,000	kW faccap	$1.52	per kW faccap	$55
Greater than 4,000 kW		48,918	kW faccap	$1.21	per kW faccap	$59
Primary Facilities Charge						
First 1,000 kW		314,400	kW faccap	$1.48	per kW faccap	$465
1,001-4,000 kW		997,128	kW faccap	$1.48	per kW faccap	$1,476
Greater than 4,000 kW		1,463,264	kW faccap	$1.17	per kW faccap	$1,712
Subtransmission Facilities Charge						
First 1,000 kW		72,000	kW faccap	$1.48	per kW faccap	$107
1,001-4,000 kW		216,000	kW faccap	$1.48	per kW faccap	$320
Greater than 4,000 kW		386,424	kW faccap	$1.17	per kW faccap	$452
Secondary Demand Charge		45,938	kW on-peak	$2.66	per kW on-peak demand	$122
Primary Demand Charge		2,477,606	kW on-peak	$2.58	per kW on-peak demand	$6,392
Subtransmission Demand Charge		602,060	kW on-peak	$1.29	per kW on-peak demand	$777
Secondary System Usage Charge Calc						
COS Franchise Fees & Other		0	MWh	0.87	mills/kWh	$0
Cust Impact Offset		0	MWh	0.39	mills/kWh	$0
COS System Usage Charge		0	MWh	1.26	mills/kWh	$0
DA Franchise Fees & Other		13,399	MWh	(0.37)	mills/kWh	($5)
Cust Impact Offset		13,399	MWh	0.39	mills/kWh	$5
DA System Usage Charge		13,399	MWh	0.02	mills/kWh	$0
Primary System Usage Charge Calc						
COS Franchise Fees & Other		469,240	MWh	0.83	mills/kWh	$389
Cust Impact Offset		469,240	MWh	0.39	mills/kWh	$183
COS System Usage Charge		469,240	MWh	1.22	mills/kWh	$572
DA Franchise Fees & Other		888,772	MWh	(0.39)	mills/kWh	($347)
Cust Impact Offset		888,772	MWh	0.39	mills/kWh	$347
DA System Usage Charge		888,772	MWh	0.00	mills/kWh	$0
Subtransmission System Usage Charge Calc						
COS Franchise Fees & Other		58,071	MWh	0.81	mills/kWh	$47
Cust Impact Offset		58,071	MWh	0.39	mills/kWh	$23
COS System Usage Charge		58,071	MWh	1.20	mills/kWh	$70
DA Franchise Fees & Other		168,932	MWh	(0.39)	mills/kWh	($66)
Cust Impact Offset		168,932	MWh	0.39	mills/kWh	$66
DA System Usage Charge		168,932	MWh	0.00	mills/kWh	$0
Secondary Energy Charge						
On-peak		0	MWh	61.07	mills/kWh	$0
Off-peak		0	MWh	46.07	mills/kWh	$0
Primary Energy Charge						
On-peak		279,899	MWh	60.07	mills/kWh	$16,814
Off-peak		189,341	MWh	45.07	mills/kWh	$8,534
Subtransmission Energy Charge						
On-peak		37,885	MWh	59.32	mills/kWh	$2,247
Off-peak		20,186	MWh	44.32	mills/kWh	$895
Reactive Demand Charge		577,233	kVar	0.50	kVar	$289
Subtotal						$43,383
					w/o CIO	$42,759

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 90						
Primary Voltage Service						
Allocations						
Functional Costs						
Primary Basic Charge	$317	4	Customers	$6,599.53	per cust, per mo.	$317
Transmission & Related Service Charge	$2,516	2,571,323	kW on-peak	$0.98	per kW on-peak demand	$2,520
Distribution Charges						
Feeder Backbone	$2,096	2,657,216	kW faccap	$0.79	per kW faccap	$2,099
Subtransmission Demand Charge	$3,698	2,571,323	kW on-peak	$1.44	per kW on-peak demand	$3,703
Substation Demand Charge	$3,818	2,571,323	kW on-peak	$1.48	per kW on-peak demand	$3,806
Primary Franchise Fees & Other	$1,206	1,758,397	MWh	0.69	mills/kWh	$1,213
Energy Charge	$91,678	1,758,397	MWh	52.14	mills/kWh	$91,683
Subtotal	$105,330					$105,340
Pricing						
Functional Costs						
Primary Basic Charge		4	Customers	$6,600.00	per cust, per mo.	$317
Primary Trans. & Rel. Serv. Charge		2,571,323	kW on-peak	$0.77	per kW on-peak demand	$1,980
Distribution Charges						
Primary Facilities Charge						
First 4,000 kW		192,000	kW faccap	$1.59	per kW faccap	$305
Over 4,000 kW		2,465,216	kW faccap	$1.28	per kW faccap	$3,155
Primary Demand Charge		2,571,323	kW on-peak	$2.58	per kW on-peak demand	$6,634
Primary System Usage Charge Calc						
COS Franchise Fees & Other		1,758,397	MWh	0.69	mills/kWh	$1,213
Cust Impact Offset		1,758,397	MWh	0.09	mills/kWh	$158
COS System Usage Charge		1,758,397	MWh	0.78	mills/kWh	$1,372
Primary Energy Charge						
On-peak		1,014,259	MWh	58.49	mills/kWh	$59,324
Off-peak		744,139	MWh	43.49	mills/kWh	$32,363
Reactive Demand Charge		68,288	kVar	$0.50	kVar	$34
						$105,484
					w/o CIO	$105,326

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2019

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULES 91 & 95						
Street & Highway Lighting						
Allocations						
Functional Costs						
Basic Charge	$1,927	203	Customers	$791.05	per cust, per mo.	$1,927
Trans. & Rel. Serv. Charge	$83	53,482	MWh	1.55	mills/kWh	$83
Distribution Charge	$1,350	53,482	MWh	25.25	mills/kWh	$1,350
Franchise Fees & Other	$249	53,482	MWh	4.65	mills/kWh	$249
COS Energy Charge	$2,769	53,482	MWh	51.77	mills/kWh	$2,769
Fixed Charges	$5,267					$5,267
Subtotal	$11,644					$11,645
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		53,482	MWh	1.55	mills/kWh	$83
Distribution Charge		53,482	MWh	61.28	mills/kWh	$3,277
System Usage Charge Calc						
Franchise Fees & Other		53,482	MWh	4.65	mills/kWh	$249
Cust Impact Offset		53,482	MWh	(1.18)	mills/kWh	($63)
System Usage Charge		53,482	MWh	3.47	mills/kWh	$186
COS Energy Charge		53,482	MWh	51.77	mills/kWh	$2,769
Fixed Charges		53,482	MWh			$5,267
Subtotal						$11,581
					w/o CIO	$11,645
SCHEDULE 92						
Traffic Signals						
Allocations						
Functional Costs						
Basic Charge	$51	17	Customers	$249.06	per cust, per mo.	$51
Trans. & Rel. Serv. Charge	$4	2,496	MWh	1.63	mills/kWh	$4
Distribution Charge	$24	2,496	MWh	9.53	mills/kWh	$24
Franchise Fees & Other	$3	2,496	MWh	1.35	mills/kWh	$3
COS Energy Charge	$133	2,496	MWh	53.22	mills/kWh	$133
Subtotal	$215					$215
Pricing						
Functional Costs						
Trans. & Rel. Serv. Charge		2,496	MWh	1.63	mills/kWh	$4
Distribution Charge		2,496	MWh	29.88	mills/kWh	$75
System Usage Charge Calc						
Franchise Fees & Other		2,496	MWh	1.35	mills/kWh	$3
Cust Impact Offset		2,496	MWh	0.00	mills/kWh	$0
System Usage Charge		2,496	MWh	1.35	mills/kWh	$3
COS Energy Charge		2,496	MWh	53.22	mills/kWh	$133
Subtotal						$215
					w/o CIO	$215

Summary of Inputs	Allocated Inputs	DesSumm	Deltas
Functional Costs			
Basic Charge	$326,742	$326,742	$0
Trans. & Rel. Serv. Charge	$37,966	$37,966	$0
Distribution Charge	$402,226	$402,226	$0
Fixed Charges	$6,881	$6,881	$0
Franchise Fees & Other	$32,153	$32,153	$0
Energy Charge	$1,061,392	$1,061,392	$0
Subtotal	$1,867,360	$1,867,360	

Functional Costs Revenues	Annual Revenue	Revenue	Deltas		
Basic Charge	$168,398	$168,398	$0		
Trans. & Rel. Serv. Charge	$37,980	$37,970	($11)	($11)	(Voluntary TOU)
Distribution Charges	$542,094	$541,994	($100)	$26	(Voluntary TOU)
Fixed Charges	$6,881	$6,881	$0		
System Usage Charge	$49,212	$49,212	$0		
Energy Charge	$1,061,372	$1,061,376	$4	$4	(Voluntary TOU)
Reactive	$1,324	$1,324	$0		
Subtotal	$1,867,262	$1,867,156	($107)	$19	

Note: figures are before employee discount and Schedule 129

On-peak demand	23,189,508	23,189,508	0
Facility Capacity	27,718,517	27,718,517	0
kVar	2,648,738	2,648,738	0

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at Current Prices ($000)	2019 Allocated Costs ($000)	Percent Change	Impact Offset Amount	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,502,509	$939,338	$998,861	6.3%		7,502,509	(0.09)	($675)
Schedule 15	15,630	$3,427	$3,397	-0.9%			4.03	$63
Schedule 32	1,590,863	$180,162	$193,013	7.1%		1,590,863	(0.09)	($143)
Schedule 38	30,626	$4,068	$4,257	4.6%			0.00	$0
Schedule 47	21,544	$4,253	$4,458	4.8%			0.00	$0
Schedule 49	64,947	$9,424	$9,627	2.2%			0.00	$0
Schedule 83	2,753,722	$251,351	$260,922	3.8%			0.00	$0
Schedule 85	2,766,237	$239,512	$240,840	0.6%			0.00	$0
Schedule 89	527,311	$54,054	$52,967	-2.0%		527,311	0.39	$206
Schedule 90	1,758,397	$102,246	$105,330	3.0%		1,758,397	0.09	$158
Schedules 91 & 95	53,482	$11,617	$11,644	0.2%			(1.18)	($63)
Schedule 92	2,496	$205	$215	4.6%			0.00	$0
COS TOTALS	17,087,764							
Sch 485 Energy	881,587						0.00	$0
Sch 489 Energy	1,071,103					1,071,103	0.39	$418
Totals	19,040,454	$1,799,658	$1,885,530	4.8%	$0	12,450,184		($37)

PORTLAND GENERAL ELECTRIC
2019 Test Period Functionalized Revenue Requirement

Function	Amount	Spread
PRODUCTION	$1,061,408	$1,061,408
TRANSMISSION	$33,133	$33,133
ANCILLARY	$4,832	$4,832
DISTRIBUTION	$638,739	$638,739
METERING	$10,827	$10,827
BILLING	$70,921	$70,921
CONSUMER	$64,762	$64,762
TOTALS	$1,884,622	$1,884,622
Schedule 129		($18,170)
Employee Discount		$946
Partial Requirements Transmission		$0
Partial Requirements Distribution		$0
Spread Total		$1,867,397

Note: Employee discount is allocated to distribution

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2019 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$686,099	$686,089
Net Variable Power Costs	$375,309	$375,303
Production Costs	$1,061,408	$1,061,392
Ancillary Services	$4,832	$4,832
Transmission		
Transmission	$33,133	
Partial Requirements Daily Demand	$0	
Transmission Costs	$33,133	$33,134
Distribution Services	$638,739	
Franchise	($47,825)	
Uncollectibles	($6,466)	
Trojan Decommissioning	($2,500)	
Partial Requirements Daily Demand	$0	
Employee Discount	$946	$946
Distribution Costs	$582,894	$582,877
Consumer Services		
Metering Services	$10,827	$10,827
Billing Services	$70,921	$70,919
Other Consumer Services	$64,762	$64,760
Franchise Fees	$47,825	$47,823
Uncollectibles	$6,466	$6,466
Trojan Decommissioning	$2,500	$2,500
Schedule 129	($18,170)	($18,170)
Totals	$1,867,397	$1,867,360
Net of employee discount	$1,866,452	$1,866,414
Net of Sch 129	$1,884,622	$1,884,584
Calendar MWH (COS & ESS)	19,040,981	
Cycle MWH (COS & ESS)	19,040,454	
Cycle/Cal Ratio	100.00%	
COS Calendar Energy MWH	17,087,349	
COS Cycle MWH	17,087,764	
Cycle/Cal Ratio	100.00%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2019

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocation of Load Following ($000)	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,503,729	$303,026	53.57%	$190,241	$493,266	47.60%	$775	$506,002	$505,920
Schedule 15	15,630	$568	0.06%	$221	$789	0.08%	$1	$809	$809
Schedule 32	1,591,586	$63,346	8.68%	$30,818	$94,164	9.09%	$148	$96,595	$96,551
Schedule 38	30,597	$1,261	0.12%	$416	$1,677	0.16%	$3	$1,720	$1,722
Schedule 47	21,528	$874	0.17%	$610	$1,485	0.14%	$2	$1,523	$1,524
Schedule 49	64,969	$2,638	0.51%	$1,817	$4,456	0.43%	$7	$4,571	$4,569
Schedule 83	2,758,034	$110,562	14.64%	$51,995	$162,557	15.69%	$255	$166,754	$166,493
Schedule 85	2,765,981	$109,545	13.27%	$47,132	$156,676	15.12%	$246	$160,722	$160,737
Schedule 89	516,290	$19,873	1.99%	$7,070	$26,944	2.60%	$294	$27,891	$28,487
Schedule 90	1,763,027	$67,405	6.77%	$24,034	$91,439	8.82%	($1,737)	$91,919	$91,678
Schedule 91/95	53,482	$1,942	0.21%	$757	$2,699	0.26%	$4	$2,769	$2,769
Schedule 92	2,496	$97	0.01%	$33	$130	0.01%	$0	$133	$133
TOTAL	17,087,349	$681,136	100.0%	$355,145	$1,036,281	100.00%	$0	$1,061,408	$1,061,392
Simple Cycle Proxy Plant $/kW				$106.42		TARGET		$1,061,408	
Projected Peak Load				3,337					
Marginal Capacity Costs ($000)				$355,145					

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT

Schedules	12 CP MW	Unit Marginal Cost	Marginal Cost	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	1,465.0	$11.98	$17,551	50.188996%	$16,629
Schedule 15	1.8	$11.98	$22	0.06%	$21
Schedule 32	257.8	$11.98	$3,089	8.83%	$2,927
Schedule 38	4.0	$11.98	$48	0.14%	$45
Schedule 47	3.5	$11.98	$42	0.12%	$40
Schedule 49	10.7	$11.98	$128	0.37%	$121
Schedule 83	457.7	$11.98	$5,483	15.68%	$5,195
Schedule 85	426.3	$11.98	$5,107	14.61%	$4,839
Schedule 89	66.3	$11.98	$794	2.27%	$752
Schedule 90-P	219.4	$11.98	$2,628	7.51%	$2,490
Schedules 91/95	6.2	$11.98	$74	0.21%	$70
Schedule 92	0.3	$11.98	$4	0.01%	$3
Totals	2,918.9		$34,969		
Target				100.00%	$33,134
Unit Marginal Cost $/kW		**$11.98**			

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE REVENUE REQUIREMENT
2019

Schedules	Production Allocation Percent	Class Revenue Requirement
Schedule 7	47.60%	$2,300
Schedule 15	0.08%	$4
Schedule 32	9.09%	$439
Schedule 38	0.16%	$8
Schedule 47	0.14%	$7
Schedule 49	0.43%	$21
Schedule 83	15.69%	$758
Schedule 85	15.12%	$731
Schedule 89	2.60%	$126
Schedule 90-P	8.82%	$426
Schedules 91/95	0.26%	$13
Schedule 92	0.01%	$1
TOTAL	100.00%	$4,832
	TARGET	$4,832

PORTLAND GENERAL ELECTRIC
Applicable 2019 Ancillary Services Charges

Line	Ancillary Service	Billing Determinant	OATT Price	Total
	SCHEDULE 1 - SCHEDULING, SYSTEM CONTROL and DISPATCH		$/MW year	
1	12 CP MW Average	2,919	$149.89	$437,519
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	2,918,933	$0.461	$1,345,628
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW Charge: $6.695 per kW per month x .013	35,027,200	$0.09	$3,048,592
4		**ANCILLARY SERVICES TOTAL**		$4,831,740

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2019

Schedules	Cycle Generation Revenues	Allocation Percent	Class Revenue Requirement
Schedule 7	$506,040,146	43.26%	$1,081
Schedule 15	$809,165	0.07%	$2
Schedule 32	$96,613,102	8.26%	$206
Schedule 38	$1,721,590	0.15%	$4
Schedule 47	$1,524,233	0.13%	$3
Schedule 49	$4,569,039	0.39%	$10
Schedule 83	$166,481,833	14.23%	$356
Schedule 85-S	$160,026,183	13.68%	$342
Schedule 89-S	$750,222	0.06%	$2
Schedule 85-P	$51,468,275	4.40%	$110
Schedule 89-P	$73,174,231	6.25%	$156
Schedule 89-T	$12,122,539	1.04%	$26
Schedule 90-P	$91,686,588	7.84%	$196
Schedule 91/95	$2,768,763	0.24%	$6
Schedule 92	$132,837	0.01%	$0
TOTAL	$1,169,888,748		$2,500
		TARGET	$2,500

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2019

Schedules	Distribution Allocations	Transmission Allocations	Generation Allocations	Schedule 129 Allocations	Subtotal Allocations	Distribution Fran. Fee Allocations	Transmission Fran. Fee Allocations	Generation Fran. Fee Allocations	Schedule 129 Fran. Fee Allocations	Total Fran. Fee Allocations
Schedule 7	$455,899	$18,929	$505,920		$980,748	$11,748	$488	$13,037		$25,272
Schedule 15	$2,492	$24	$809		$3,326	$64	$1	$21		$86
Schedule 32	$89,727	$3,366	$96,551		$189,644	$2,312	$87	$2,488		$4,887
Schedule 38	$2,403	$53	$1,722		$4,178	$62	$1	$44		$108
Schedule 47	$2,795	$47	$1,524		$4,366	$72	$1	$39		$113
Schedule 49	$4,734	$142	$4,569		$9,445	$122	$4	$118		$243
Schedule 83	$84,482	$5,953	$166,493		$256,929	$2,177	$153	$4,290		$6,621
Schedule 85	$63,892	$5,570	$160,737	$7,980	$238,178	$1,646	$144	$4,142	$211	$6,143
Schedule 89	$13,175	$1,278	$28,487	$10,190	$53,129	$340	$33	$734	$257	$1,363
Schedule 90-P	$10,125	$2,516	$91,678		$104,320	$261	$65	$2,362		$2,688
Schedules 91/95	$8,550	$83	$2,769		$11,402	$220	$2	$71		$294
Schedule 92	$75	$4	$133		$212	$2	$0	$3		$5
TOTALS	$738,349	$37,966	$1,061,392	$18,170	$1,855,876	$19,026	$978	$27,350	$468	$47,823

Franchise Fee Revenue Requirement **$47,823**

Schedules	Distribution MWh	Distribution mills/kWh	Transmission MWh	Transmission mills/kWh	Generation MWh	Generation mills/kWh	Schedule 129 MWh	Schedule 129 mills/kWh	Total COS mills/kWh	Total DA mills/kWh	Difference COS/DA mills/kWh
Schedule 7	7,502,509	1.57	7,502,509	0.07	7,502,509	1.74	0		3.37		
Schedule 15	15,630	4.11	15,630	0.04	15,630	1.33	0		5.48	4.11	1.37
Schedule 32	1,590,863	1.45	1,590,863	0.05	1,590,863	1.56	0		3.07	1.45	1.62
Schedule 38	30,626	2.02	30,626	0.04	30,626	1.45	0		3.52	2.02	1.49
Schedule 47	21,544	3.34	21,544	0.06	21,544	1.82	0		5.22		
Schedule 49	64,947	1.88	64,947	0.06	64,947	1.81	0		3.75	1.88	1.87
Schedule 83	2,753,722	0.79	2,753,722	0.06	2,753,722	1.56	0		2.40	0.79	1.61
Schedule 85-S	2,743,509	0.45	2,178,260	0.05	2,178,260	1.50	565,248	0.24	2.01	0.69	1.32
Schedule 89-S	13,399	0.22	0	0.06	0	1.42	13,399	0.24	1.70	0.46	1.24
Schedule 85-P	904,314	0.44	587,976	0.05	587,976	1.48	316,338	0.24	1.97	0.68	1.29
Schedule 89-P	1,358,012	0.21	469,240	0.06	469,240	1.39	888,772	0.24	1.67	0.45	1.22
Schedule 89-T	227,004	0.21	58,071	0.06	58,071	1.37	168,932	0.24	1.65	0.45	1.20
Schedule 90-P	1,758,397	0.15	1,758,397	0.04	1,758,397	1.34			1.53	0.15	1.38
Schedule 91/95	53,482	4.12	53,482	0.04	53,482	1.33	0		5.49	4.12	1.37
Schedule 92	2,496	0.77	2,496	0.04	2,496	1.37	0		2.19	0.77	1.41
TOTALS	19,040,454		17,087,764		17,087,764		1,952,690				

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2019

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 85-S	2,743,509	39.2%	$0	0.00
Schedule 89-S	13,399	0.2%	$0	0.00
Schedule 85-P	904,314	12.9%	$0	0.00
Schedule 89-P	1,358,012	19.4%	$0	0.00
Schedule 90-P	1,758,397	25.1%	$0	0.00
Schedule 89-T	227,004	3.2%	$0	0.00
TOTAL	7,004,635	100.00%	$0	
		TARGET	$0	0.00

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,502,509	39.4%	($7,159)	(0.95)
Schedule 15	15,630	0.1%	($15)	(0.95)
Schedule 32	1,590,863	8.4%	($1,518)	(0.95)
Schedule 38	30,626	0.2%	($29)	(0.95)
Schedule 47	21,544	0.1%	($21)	(0.95)
Schedule 49	64,947	0.3%	($62)	(0.95)
Schedule 83	2,753,722	14.5%	($2,628)	(0.95)
Schedule 85-S	2,743,509	14.4%	($2,618)	(0.95)
Schedule 89-S	13,399	0.1%	($13)	(0.95)
Schedule 85-P	904,314	4.7%	($863)	(0.95)
Schedule 89	1,358,012	7.1%	($1,296)	(0.95)
Schedule 89-T	227,004	1.2%	($217)	(0.95)
Schedule 90-P	1,758,397	9.2%	($1,678)	(0.95)
Schedules 91/95	53,482	0.3%	($51)	(0.95)
Schedule 92	2,496	0.0%	($2)	(0.95)
TOTAL	19,040,454	100.00%	($18,170)	(0.95)
		TARGET	($18,170)	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF UNCOLLECTIBLES
2019

Grouping	Marginal Cost Allocation Percent	Class Revenue Requirement
Schedule 7		
Single Phase	92.58%	$5,986
Three Phase	0.02%	$1
Schedule 15		
Residential	0.47%	$30
Commercial	0.34%	$22
Schedule 32		
Single Phase	2.81%	$182
Three Phase	1.88%	$122
Schedule 38		
Single Phase	0.00%	$0
Three Phase	0.00%	$0
Schedule 47		
Single Phase	0.01%	$0
Three Phase	0.09%	$6
Schedule 49		
Single Phase	0.00%	$0
Three Phase	0.09%	$6
Schedule 83		
Single Phase	0.07%	$4
Three Phase	1.05%	$68
Schedule 85		
Secondary	0.50%	$32
Primary	0.08%	$5
Schedule 89		
Secondary	0.00%	$0
Primary	0.00%	$0
Subtransmission	0.00%	$0
Schedule 90-P	0.00%	$0
Schedules 91/95	0.00%	$0
Schedule 92	0.00%	$0
TOTAL	100.00%	$6,466
	TARGET	$6,466

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2019

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	781,021	Customers	$19.43	$15,175	$21,783
		Three-Phase Customers	130	Customers	$58.07	$8	$11
	Transformer & Service						
		Single-Phase Customers	781,021	Customers	$83.97	$65,582	$94,139
		Three-Phase Customers	130	Customers	$140.51	$18	$26
FACILITIES	Feeder Backbone						
		Single-Phase Customers	2,016,929	kW, rateclass peak	$20.41	$41,166	$59,090
		Three-Phase Customers	336	kW, rateclass peak	$20.41	$7	$10
	Feeder Local Facilities						
		Single-Phase Customers	3,124,085	Design Demand	$20.10	$62,794	$90,136
		Three-Phase Customers	520	Design Demand	$20.10	$10	$15
DEMAND	Subtransmission		2,046,516	kW, rateclass peak	$12.15	$24,865	$35,692
	Substation		2,017,265	kW, rateclass peak	$12.24	$24,691	$35,443
SUBTOTAL						$234,317	$336,344
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,847	Lights	$3.89	$38	$55
	Transformer & Service		9,847	Lights	$2.89	$28	$41
FACILITIES	Feeder Backbone		828	kW, rateclass peak	$21.38	$18	$25
	Feeder Local Facilities		828	Design Demand	$20.78	$17	$25
DEMAND	Subtransmission		840	kW, rateclass peak	$12.15	$10	$15
	Substation		828	kW, rateclass peak	$12.24	$10	$15
FIXED	Luminaires & Poles						$336
SUBTOTAL						$122	$511
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		10,600	Lights	$3.89	$41	$59
	Transformer & Service		10,600	Lights	$2.89	$31	$44
FACILITIES	Feeeder Backbone		3,153	kW, rateclass peak	$21.38	$67	$97
	Feeder Local Facilities		3,153	Design Demand	$20.78	$66	$94
DEMAND	Subtransmission		3,199	kW, rateclass peak	$12.15	$39	$56
	Substation		3,153	kW, rateclass peak	$12.24	$39	$55
FIXED	Luminaires & Poles						$1,278
SUBTOTAL						$282	$1,683
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$114
	Transformer & Service						$85
FACILITIES	Feeeder Backbone						$122
	Feeder Local Facilities						$119
DEMAND	Subtransmission						$70
	Substation						$70
FIXED	Luminaires & Poles						**$1,614**
SUBTOTAL							$2,194

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2019

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	56,092	Customers	$17.23	$966.47	$1,387.30
		Three-Phase Customers	37,563	Customers	$72.71	$2,731.24	$3,920.48
	Transformer & Service						
		Single-Phase Customers	56,092	Customers	$150.15	$8,422.26	$12,089.53
		Three-Phase Customers	37,563	Customers	$236.86	$8,897.27	$12,771.36
FACILITIES	Feeder Backbone						
		Single-Phase Customers	122,445	kW, rateclass peak	$24.70	$3,024.39	$4,341.29
		Three-Phase Customers	193,719	kW, rateclass peak	$24.70	$4,784.86	$6,868.30
	Feeder Local Facilities						
		Single-Phase Customers	269,243	Design Demand	$27.24	$7,334.18	$10,527.66
		Three-Phase Customers	424,467	Design Demand	$12.94	$5,492.60	$7,884.22
DEMAND	Subtransmission		320,748	kW, rateclass peak	$12.15	$3,897.09	$5,593.98
	Substation		316,164	kW, rateclass peak	$12.24	$3,869.85	$5,554.87
SUBTOTAL						$49,420.21	$70,938.99
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	55	Customers	$58.07	$3.21	$4.61
		Three-Phase Customers	337	Customers	$130.80	$44.07	$63.26
	Transformer & Service						
		Single-Phase Customers	55	Customers	$196.72	$10.87	$15.60
		Three-Phase Customers	337	Customers	$581.00	$195.75	$280.98
FACILITIES	Feeder Backbone						
		Single-Phase Customers	704	kW, rateclass peak	$24.54	$17.27	$24.78
		Three-Phase Customers	12,671	kW, rateclass peak	$24.54	$310.96	$446.36
	Feeder Local Facilities						
		Single-Phase Customers	2641	Design Demand	$26.38	$69.67	$100.01
		Three-Phase Customers	38,846	Design Demand	$13.09	$508.49	$729.91
DEMAND	Subtransmission		13,569	kW, rateclass peak	$12.15	$164.86	$236.65
	Substation		13,375	kW, rateclass peak	$12.24	$163.71	$234.99
SUBTOTAL						$1,488.85	$2,137.14
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	218	Customers	$57.73	$12.59	$18.07
		Three-Phase Customers	2,813	Customers	$86.54	$243.44	$349.44
	Transformer & Service						
		Single-Phase Customers	218	Customers	$10.77	$2.35	$3.37
		Three-Phase Customers	2813	Customers	$21.43	$60.28	$86.53
FACILITIES	Feeder Backbone						
		Single-Phase Customers	487.51813	kW, rateclass peak	$24.70	$12.04	$17.28
		Three-Phase Customers	12517.4819	kW, rateclass peak	$24.70	$309.18	$443.81
	Feeder Local Facilities						
		Single-Phase Customers	2267	Design Demand	$23.90	$54.18	**$77.77**
		Three-Phase Customers	44164	Design Demand	$11.35	$501.26	$719.52
DEMAND	Subtransmission		13193	kW, rateclass peak	$12.15	$160.29	**$230.09**
	Substation		13005	kW, rateclass peak	$12.24	$159.18	**$228.49**
SUBTOTAL						$1,514.79	$2,174.37

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2019

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	7	Customers	$58.07	$0.41	$0.58
		Three-Phase Customers	1297	Customers	$71.36	$92.55	$132.85
	Transformer & Service						
		Single-Phase Customers	7	Customers	$144.93	$1.01	$1.46
		Three-Phase Customers	1297	Customers	$144.93	$187.97	$269.82
FACILITIES	Feeder Backbone						
		Single-Phase Customers	196.010736	kW, rateclass peak	$24.54	$4.81	$6.90
		Three-Phase Customers	36317.9893	kW, rateclass peak	$24.54	$891.24	$1,279.31
	Feeder Local Facilities						
		Single-Phase Customers	260	Design Demand	$24.34	$6.33	$9.08
		Three-Phase Customers	72762	Design Demand	$12.08	$878.96	$1,261.69
DEMAND	Subtransmission		37044	kW, rateclass peak	$12.15	$450.08	$646.06
	Substation		36514	kW, rateclass peak	$12.24	$446.93	$641.54
SUBTOTAL						$2,960.31	$4,249.30
Schedule 83 General Service (31-200 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	661	Customers	$57.73	$38.15	$54.77
		Three-Phase Customers	10,688	Customers	$129.44	$1,383.43	$1,985.81
	Transformer & Service						
		Single-Phase Customers	661	Customers	$388.14	$256.53	$368.23
		Three-Phase Customers	10,688	Customers	$1,050.66	$11,229.28	$16,118.78
FACILITIES	Feeder Backbone						
		Single-Phase Customers	17,217	kW, rateclass peak	$24.54	$422.51	$606.49
		Three-Phase Customers	566,783	kW, rateclass peak	$24.54	$13,908.85	$19,965.10
	Feeder Local Facilities						
		Single-Phase Customers	26,238	Design Demand	$26.38	$692.16	$993.54
		Three-Phase Customers	862,508	Design Demand	$13.09	$11,290.23	$16,206.27
DEMAND	Subtransmission		592,468	kW, rateclass peak	$12.15	$7,198.49	$10,332.88
	Substation		584,000	kW, rateclass peak	$12.24	$7,148.16	$10,260.65
SUBTOTAL						$53,567.79	$76,892.53
Schedule 85 General Service (201-4,000 kW)							
CUSTOMER	Meters						
		Secondary Customers	1,421	Customers	$162.33	$230.73	$331.19
		Primary Customers	239	Customers	$1,805.54	$431.07	$618.77
	Transformer & Service						
		Secondary Customers	1,421	Customers	$2,419.89	$3,439.47	$4,937.10
		Primary Customers	239	Customers	$0.00	$0.00	$0.00
FACILITIES	Feeder Backbone		675,700	kW, rateclass peak	$19.54	$13,203.18	$18,952.17
	Feeder Local Facilities		903,915	Design Demand	$7.12	$6,435.87	$9,238.21
DEMAND	Subtransmission		685,498	kW, rateclass peak	$12.15	$8,328.80	$11,955.37
	Substation		675,700	kW, rateclass peak	$12.24	$8,270.57	$11,871.78
SUBTOTAL						$40,339.69	$57,904.59

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2019

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (4,000 plus kW)							
CUSTOMER	Meters						
		Secondary Meters	1	Customers	$175.85	$0.18	$0.25
		Primary Meters	27	Customers	$1,809.13	$48.85	$70.12
		Substation Meters	6	Customers	$19,774.56	$118.65	$170.31
	Transformer & Service						
		Secondary Customers	1	Customers	$14,124.26	$14.12	$20.27
		Primary Customers	27	Customers	$0.00	$0.00	$0.00
FACILITIES	Feeder Backbone						
		Secondary Customers	1	Customers	$76,614.00	$76.61	$109.97
		Primary Customers	27	Customers	$76,614.00	$2,068.58	$2,969.29
		Subtransmission 115 kV Feeder	6	Customers	$77,041.00	$462.25	$663.52
DEMAND	Subtransmission		233,598	kW, rateclass peak	$12.15	$2,838.22	$4,074.04
	Substation (Sec. & Prim. Only)		197,745	kW, rateclass peak	$12.24	$2,420.40	$3,474.30
SUBTOTAL						$8,047.85	$11,552.08
Schedule 90 Primary Voltage Service							
CUSTOMER	Meters						
		Primary Meters	4	Customers	$1,805.54	$7.22	$10.37
FACILITIES	Feeder Backbone						
		Primary Customers	4	Customers	$365,087.00	$1,460.35	$2,096.22
DEMAND	Subtransmission		236,214	kW, rateclass peak	$12.15	$2,870.00	$4,119.67
	Substation (Sec. & Prim. Only)		232,838	kW, rateclass peak	$12.24	$2,849.94	$4,090.87
SUBTOTAL						$7,187.51	$10,317.13

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT
2019

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedules 91 & 95 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	155,807	Lights	$3.89	$605.40	$869.00
	Transformer & Service	155,807	Lights	$2.89	$450.28	$646.35
FACILITIES	Feeder Backbone	13,623	kW, rateclass peak	$21.38	$291.26	$418.08
	Feeder Local Facilities	13,623	Design Demand	$23.11	$314.83	$451.91
DEMAND	Subtransmission	13,820	kW, rateclass peak	$12.15	$167.91	$241.03
	Substation	13,623	kW, rateclass peak	$12.24	$166.75	$239.35
FIXED	Luminaires & Poles					**$5,266.77**
SUBTOTAL					$1,996.43	$8,132.49
Schedule 92 Traffic Signals						
CUSTOMER	Transformer & Service	1,248	Intersections	$9.19	$11.47	$16.46
FACILITIES	Feeder Backbone	294	kW, rateclass peak	$21.38	$6.29	$9.02
	Feeder Local Facilities	294	Design Demand	$10.44	$3.07	$4.41
DEMAND	Subtransmission	298	kW, rateclass peak	$12.15	$3.62	$5.20
	Substation	294	kW, rateclass peak	$12.24	$3.60	$5.17
SUBTOTAL					$28.04	$40.25
Summary						
CUSTOMER	Meters	892,581	Customers		$21,535.04	$30,911.92
	Transformer & Service		Customers		$98,838.64	$141,875.43
	Customer Service	176,254	Lights		$684.85	$983.04
FACILITIES	Feeder Backbone	3,673,921	kW, rateclass peak		$82,512.11	$118,439.92
	Feeder Local Facilities	5,789,814	Design Demand		$96,469.13	$138,474.17
DEMAND	Subtransmission	4,197,005	kW, rateclass peak		$50,993.61	$73,197.49
	Substation	4,104,504	kW rateclass peak		$50,239.13	$72,114.49
FIXED	Luminaires & Poles					$6,881.01
TOTALS					$401,272.51	$582,877.46
					TARGET	$582,877.46
				EQUAL PERCENT		$1.44

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2019

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	781,021	$0.31	$242	$7,183
Three Phase	130	$0.31	$0	$1
Schedule 15				
Residential	5,491	$0.00	$0	$0
Commercial	3,995	$0.00	$0	$0
Schedule 32				
Single Phase	56,092	$0.69	$39	$1,148
Three Phase	37,563	$0.69	$26	$769
Schedule 38				
Single Phase	55	$11.27	$1	$18
Three Phase	337	$11.27	$4	$113
Schedule 47				
Single Phase	218	$1.05	$0	$7
Three Phase	2,813	$1.05	$3	$88
Schedule 49				
Single Phase	7	$1.18	$0	$0
Three Phase	1,297	$1.18	$2	$45
Schedule 83				
Single Phase	661	$2.57	$2	$50
Three Phase	10,688	$2.57	$27	$815
Schedule 85				
Secondary	1,421	$11.93	$17	$503
Primary	239	$11.93	$3	$85
Schedule 89				
Secondary	1	$1.48	$0	$0
Primary	27	$1.48	$0	$1
Subtransmission	6	$1.48	$0	$0
Schedule 90-P	4	$0.21	$0	$0
Schedules 91/95	203	$0.00	$0	$0
Schedule 92	17	$0.00	$0	$0
TOTAL	902,287		$365	$10,827
			TARGET	$10,827
		EQUAL PERCENT		2967%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2019

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	781,021	$39.01	$30,468	$62,384
Three Phase	130	$39.01	$5	$10
Schedule 15				
Residential	5,491	$6.28	$34	$71
Commercial	3,995	$8.06	$32	$66
Schedule 32				
Single Phase	56,092	$33.09	$1,856	$3,800
Three Phase	37,563	$33.09	$1,243	$2,545
Schedule 38				
Single Phase	55	$41.14	$2	$5
Three Phase	337	$41.14	$14	$28
Schedule 47				
Single Phase	218	$33.15	$7	$15
Three Phase	2,813	$33.15	$93	$191
Schedule 49				
Single Phase	7	$36.48	$0	$1
Three Phase	1,297	$36.48	$47	$97
Schedule 83				
Single Phase	661	$41.59	$27	$56
Three Phase	10,688	$41.59	$445	$910
Schedule 85				
Secondary	1,421	$83.38	$119	$243
Primary	239	$83.38	$20	$41
Schedule 89				
Secondary	1	$181.76	$0	$0
Primary	27	$181.76	$5	$10
Subtransmission	6	$181.76	$1	$2
Schedule 90-P	4	$17.96	$0	$0
Schedules 91/95	203	$984.82	$200	$409
Schedule 92	17	$981.15	$17	$34
TOTAL	902,287		$34,636	$70,919
			TARGET	$70,919
		EQUAL PERCENT		205%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2019

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7				
Single Phase	781,021	$24.05	$18,784	$42,900
Three Phase	130	$24.05	$3	$7
Schedule 15				
Residential	5,491	$4.95	$27	$62
Commercial	3,995	$4.95	$20	$45
Schedule 32				
Single Phase	56,092	$46.82	$2,626	$5,998
Three Phase	37,563	$46.82	$1,759	$4,017
Schedule 38				
Single Phase	55	$109.69	$6	$14
Three Phase	337	$109.69	$37	$84
Schedule 47				
Single Phase	218	$44.91	$10	$22
Three Phase	2,813	$44.91	$126	$289
Schedule 49				
Single Phase	7	$109.48	$1	$2
Three Phase	1,297	$109.48	$142	$324
Schedule 83				
Single Phase	661	$205.64	$136	$310
Three Phase	10,688	$205.64	$2,198	$5,020
Schedule 85				
Secondary	1,421	$1,220.21	$1,734	$3,961
Primary	239	$1,220.21	$291	$665
Schedule 89				
Secondary	1	$9,411.51	$9	$21
Primary	27	$9,411.51	$254	$580
Subtransmission	6	$9,411.51	$56	$129
Schedule 90-P	4	$33,521.59	$134	$306
Schedule 91/95	203	$4.95	$1	$2
Schedule 92	17	$4.95	$0	$0
TOTAL	902,287		$28,355	$64,760
			TARGET	$64,760
		EQUAL PERCENT		228%

PORTLAND GENERAL ELECTRIC

PROPOSED
Summary of Area and Streetlighting Revenue

Schedule 15 - Area Lighting	
Fixtures & Maintenance	$978,511
Poles	$635,721
Energy (volumetric c/kWh rate)	$1,845,587
Total	**$3,459,819**

Schedule 91/95 - Street and Highway Lighting	
Fixtures & Maintenance (Options A&B)	$2,676,178
Poles (Options A&B)	$2,590,596
Energy (volumetric c/kWh rate)	$6,315,343
Total	**$11,582,118**

PORTLAND GENERAL ELECTRIC
Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	B	C	TOTAL	Proposed Sch 91 & 95 A & B Counts A	B	C	TOTAL	Annual MWh	Annual Fixed Revenue A	B	Annual Energy
79	Cobrahead - PD	HPS	70-watt	30	Standard	$0.00	$1.29	$3.54	$0.00	$3.19	$1.90		-	-	2	2	30	$0	$0	$85
84	Cobrahead - PD	HPS	100-watt	43	Standard	$0.00	$1.28	$5.08	$0.00	$4.01	$2.73		-	4	58	62	43	$0	$61	$3,780
85	Cobrahead - PD	HPS	150-watt	62	Standard	$0.00	$1.29	$7.32	$0.00	$5.22	$3.93		-	-	20	20	62	$0	$0	$1,757
89	Cobrahead - PD	HPS	200-watt	79	Standard	$0.00	$1.32	$9.33	$0.00	$6.33	$5.01		-	2	103	105	79	$0	$32	$11,756
86	Cobrahead - PD	HPS	250-watt	102	Standard	$0.00	$1.30	$12.04	$0.00	$7.76	$6.46		-	-	310	310	102	$0	$0	$44,789
87	Cobrahead - PD	HPS	400-watt	163	Standard	$0.00	$1.34	$19.25	$0.00	$11.67	$10.33		-	1	25	26	163	$0	$16	$6,006
33	Cobrahead	HPS	70-watt	30	Standard	$4.85	$1.51	$3.54	$6.75	$3.41	$1.90		16	60	276	352	30	$931	$1,087	$14,953
34	Cobrahead	HPS	100-watt	43	Standard	$4.85	$1.51	$5.08	$7.58	$4.24	$2.73		498	2,227	269	2,994	43	$28,984	$40,353	$182,514
35	Cobrahead	HPS	150-watt	62	Standard	$4.96	$1.53	$7.32	$8.89	$5.46	$3.93		30	283	412	725	62	$1,786	$5,196	$63,684
39	Cobrahead	HPS	200-watt	79	Standard	$5.72	$1.58	$9.33	$10.73	$6.59	$5.01		125	1,920	448	2,493	79	$8,580	$36,403	$279,116
36	Cobrahead	HPS	250-watt	102	Standard	$5.60	$1.56	$12.04	$12.06	$8.02	$6.46		27	810	479	1,316	102	$1,814	$15,163	$190,136
37	Cobrahead	HPS	400-watt	163	Standard	$5.67	$1.57	$19.25	$16.00	$11.90	$10.33		650	160	274	1,084	163	$44,226	$3,014	$250,404
31	Flood	HPS	250-watt	102	Standard	$5.89	$1.60	$12.04	$12.35	$8.06	$6.46		125	-	2	127	102	$8,835	$0	$18,349
32	Flood	HPS	400-watt	163	Standard	$5.89	$1.60	$19.25	$16.22	$11.93	$10.33		294	2	10	306	163	$20,780	$38	$70,686
40	Post-Top	HPS	100-watt	43	Standard	$5.22	$1.56	$5.08	$7.95	$4.29	$2.73		4,730	3,722	590	9,042	43	$296,287	$69,676	$551,200
76	Shoebox	HPS	70-watt	30	Standard	$6.16	$1.69	$3.54	$8.06	$3.59	$1.90		1	67	15	83	30	$74	$1,359	$3,526
77	Shoebox	HPS	100-watt	43	Standard	$5.85	$1.65	$5.08	$8.58	$4.38	$2.73		7	3,471	2,293	5,771	43	$491	$68,726	$351,800
78	Shoebox	HPS	150-watt	62	Standard	$6.16	$1.69	$7.32	$10.09	$5.62	$3.93		1	210	239	450	62	$74	$4,259	$39,528
81	Special Acorn	HPS	100-watt	43	Custom	$8.47	$1.95	$5.08	$11.20	$4.68	$2.73		684	2,375	642	3,701	43	$69,522	$55,575	$225,613
82	Victorian	HPS	150-watt	62	Custom	$8.47	$1.95	$7.32	$12.40	$5.88	$3.93		82	1,139	347	1,568	62	$8,334	$26,653	$137,733
49	Victorian	HPS	200-watt	79	Custom	$9.13	$2.04	$9.33	$14.14	$7.05	$5.01		3	129	-	132	79	$329	$3,158	$14,779
83	Victorian	HPS	250-watt	102	Custom	$9.13	$2.04	$12.04	$15.59	$8.50	$6.46		76	858	140	1,074	102	$8,327	$21,004	$155,172
64	Capitol Acorn	HPS	100-watt	43	Custom	$12.06	$2.42	$5.08	$14.79	$5.15	$2.73		43	60	3	106	43	$6,223	$1,742	$6,462
67	Capitol Acorn	HPS	150-watt	62	Custom	$10.79	$2.25	$7.32	$14.72	$6.18	$3.93		-	372	18	390	62	$0	$10,044	$34,258
65	Capitol Acorn	HPS	200-watt	79	Custom	$10.80	$2.26	$9.33	$15.81	$7.27	$5.01		1	61	-	62	79	$130	$1,654	$6,942
66	Capitol Acorn	HPS	250-watt	102	Custom	$10.79	$2.25	$12.04	$17.25	$8.71	$6.46		-	-	-	0	102	$0	$0	$0
12	Acorn - Indep.	HPS	100-watt	43	Custom	$8.62	$1.96	$5.08	$11.35	$4.69	$2.73		46	7	22	75	43	$4,758	$165	$4,572
13	Acorn - Indep.	HPS	150-watt	62	Custom	$8.62	$1.96	$7.32	$12.55	$5.89	$3.93		-	4	8	12	62	$0	$94	$1,054
98	Techtra	HPS	100-watt	43	Custom	$16.94	$3.06	$5.08	$19.67	$5.79	$2.73		533	38	2	573	43	$108,348	$1,395	$34,930
99	Techtra	HPS	150-watt	62	Custom	$16.72	$3.03	$7.32	$20.65	$6.96	$3.93		17	144	-	161	62	$3,411	$5,236	$14,142
88	Techtra	HPS	250-watt	102	Custom	$16.55	$3.01	$12.04	$23.01	$9.47	$6.46		-	60	8	68	102	$0	$2,167	$9,825
90	Westbrooke Acorn	HPS	70-watt	30	Custom	$11.01	$2.28	$3.54	$12.91	$4.18	$0.00		1	24	-	25	30	$132	$657	$1,062
91	Westbrooke Acorn	HPS	100-watt	43	Custom	$10.59	$2.22	$5.08	$13.32	$4.95	$2.73		31	383	11	425	43	$3,939	$10,203	$25,908
92	Westbrooke Acorn	HPS	150-watt	62	Custom	$15.12	$2.81	$7.32	$19.05	$6.74	$3.93		-	61	-	61	62	$0	$2,057	$5,358
93	Westbrooke Acorn	HPS	200-watt	79	Custom	$10.77	$2.25	$9.33	$15.78	$7.26	$5.01		-	5	-	5	79	$0	$135	$560
94	Westbrooke Acorn	HPS	250-watt	102	Custom	$11.34	$2.32	$12.04	$17.80	$8.78	$6.46		73	35	-	108	102	$9,934	$974	$15,604
62	Cobrahead	MH	150-watt	60	Custom	$5.37	$1.79	$7.08	$9.17	$5.59	$3.80		1	-	28	29	60	$64	$0	$2,464
61	Flood	MH	350-watt	139	Custom	$5.91	$1.75	$16.41	$14.72	$10.56	$8.81		-	-	-	0	139	$0	$0	$0
47	Flood	HPS	750-watt	285	Custom	$9.09	$2.83	$33.65	$27.15	$20.89	$18.06		57	-	-	57	285	$6,218	$0	$23,017
9	Mongoose	HPS	150-watt	62	Custom	$8.86	$2.00	$7.32	$12.79	$5.93	$3.93		-	7	-	7	62	$0	$168	$615
10	Mongoose	HPS	250-watt	102	Custom	$8.31	$1.93	$12.04	$14.77	$8.39	$0.00		-	2	-	2	102	$0	$46	$289
18	Ornamental Acorn Twin / Opt C	QL	85-watt	64	Custom	$0.00	$0.00	$7.56	$0.00	$0.00	$4.06		-	-	170	170	64	$0	$0	$15,422
20	Ornamental Acorn / Opt C	QL	55-watt	21	Custom	$0.00	$0.00	$2.48	$0.00	$0.00	$1.33		-	-	3	3	21	$0	$0	$89
26	Ornamental Acorn Twin / Opt C	QL	55-watt	42	Custom	$0.00	$0.00	$4.96	$0.00	$0.00	$2.66		-	-	-	0	42	$0	$0	$0
44	Composite Twin / Opt C	Comp	140-watt	54	Custom	$0.00	$0.00	$6.38	$0.00	$0.00	$3.42		-	-	-	0	54	$0	$0	$0
45	Composite Twin / Opt C	Comp	175-watt	66	Custom	$0.00	$0.00	$7.79	$0.00	$0.00	$4.18		-	-	-	0	66	$0	$0	$0
19	Cobrahead - (C) Only	MV	100-watt	39	Obsolete	$0.00	$0.00	$4.60	$0.00	$0.00	$2.47		-	-	1	1	39	$0	$0	$55
21	Cobrahead	MV	175-watt	66	Obsolete	$4.81	$1.47	$7.79	$8.99	$5.65	$4.18		86	515	67	668	66	$4,964	$9,085	$62,445
22	Cobrahead	MV	250-watt	94	Obsolete	$0.00	$0.00	$11.10	$0.00	$0.00	$5.96		-	-	23	23	94	$0	$0	$3,064
23	Cobrahead	MV	400-watt	147	Obsolete	$5.73	$1.59	$17.36	$15.05	$10.91	$9.32		37	15	79	131	147	$2,544	$286	$27,290
24	Cobrahead	MV	1,000-watt	374	Obsolete	$5.96	$1.86	$44.16	$29.66	$25.56	$23.70		8	1	3	12	374	$572	$22	$6,359
50	Special Box - Space-Glo	HPS	70-watt	30	Obsolete	$5.81	$0.00	$3.54	$7.71	$0.00	$0.00		21	-	-	21	30	$1,464	$0	$892

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Schedules 91 & 95, Proposed Prices, Counts and Revenue

Lum CODE	Light Description	Type	Watts	Monthly kWh	Category	Tariff Rates A	Tariff Rates B	Monthly Energy	DAX Sch 91 & 95 A & B RATES A	DAX B	DAX C	DAX TOTAL	Proposed Sch 91 & 95 A & B Counts A	Counts B	Counts C	Counts TOTAL	Annual MWh	Annual Fixed Revenue A	Annual Fixed Revenue B	Annual Energy
46	Special Box - Space-Glo	MV	175-watt	66	Obsolete	$5.77	$1.57	$7.79	$9.95	$5.75	$4.18		17	133	23	173	66	$1,177	$2,506	$16,172
51	Box - Gardco Hub / Opt C	HPS	Twin 70-watt	60	Obsolete	$0.00	$0.00	$7.08	$0.00	$0.00	$3.80		-	-	2	2	60	$0	$0	$170
52	Box - Gardco Hub / Opt C	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.54	$0.00	$0.00	$1.90		-	-	40	40	30	$0	$0	$1,699
53	Box - Gardco Hub	HPS	100-watt	43	Obsolete	$0.00	$1.90	$5.08	$0.00	$4.63	$2.73		-	4	5	9	43	$0	$91	$549
54	Box - Gardco Hub	HPS	150-watt	62	Obsolete	$0.00	$1.92	$7.32	$0.00	$5.85	$3.93		-	-	64	64	62	$0	$0	$5,622
55	Box - Gardco Hub / Opt C	HPS	250-watt	102	Obsolete	$0.00	$0.00	$12.04	$0.00	$0.00	$6.46		-	-	42	42	102	$0	$0	$6,068
56	Box - Gardco Hub / Opt C	HPS	400-watt	163	Obsolete	$0.00	$0.00	$19.25	$0.00	$0.00	$10.33		-	-	11	11	163	$0	$0	$2,541
58	Box - Gardco Hub	MH	250-watt	99	Obsolete	$0.00	$1.25	$11.69	$0.00	$7.52	$6.27		-	7	8	15	99	$0	$105	$2,104
59	Box - Gardco Hub	MH	400-watt	156	Obsolete	$0.00	$1.25	$18.42	$0.00	$11.14	$0.00		-	25	-	25	156	$0	$375	$5,526
48	Cobrahead	MH	175-watt	71	Obsolete	$0.00	$1.66	$8.38	$0.00	$6.16	$4.50		-	2	30	32	71	$0	$40	$3,218
60	Flood	MH	400-watt	156	Obsolete	$6.09	$1.81	$18.42	$15.98	$11.70	$9.89		20	2	12	34	156	$1,462	$43	$7,515
69	Cobrahead DW 70/100	HPS	100-watt	43	Obsolete	$0.00	$1.53	$5.08	$0.00	$4.26	$0.00		-	-	-	0	43	$0	$0	$0
70	Cobrahead DW 100/150	HPS	100-watt	43	Obsolete	$0.00	$1.53	$5.08	$0.00	$4.26	$0.00		-	-	-	0	43	$0	$0	$0
71	Cobrahead DW 100/150	HPS	150-watt	62	Obsolete	$0.00	$1.55	$7.32	$0.00	$5.48	$3.93		-	1	-	1	62	$0	$19	$88
2	Victorian	QL	85-watt	32	Obsolete	$0.00	$0.70	$3.78	$0.00	$2.73	$2.03		-	-	113	113	32	$0	$0	$5,126
1	Victorian	QL	165-watt	60	Obsolete	$0.00	$0.83	$7.08	$0.00	$4.63	$3.80		-	-	251	251	60	$0	$0	$21,325
3	Techtra	QL	165-watt	60	Obsolete	$17.97	$1.08	$7.08	$21.77	$4.88	$3.80		4	151	5	160	60	$863	$1,957	$13,594
95	KIM SBC Shoebox	HPS	150-watt	62	Obsolete	$0.00	$2.39	$7.32	$0.00	$6.32	$3.93		-	-	64	64	62	$0	$0	$5,622
96	KIM Archetype	HPS	250-watt	102	Obsolete	$0.00	$2.44	$12.04	$0.00	$8.90	$6.46		-	10	24	34	102	$0	$293	$4,912
97	KIM Archetype	HPS	400-watt	163	Obsolete	$0.00	$2.13	$19.25	$0.00	$12.46	$10.33		-	6	28	34	163	$0	$153	$7,854
80	Acorn Type	HPS	70-watt	30	Obsolete	$8.50	$1.98	$3.54	$10.40	$3.88	$0.00		20	10	-	30	30	$2,040	$238	$1,274
73	GardCo Bronze - (C) Only	HPS	70-watt	30	Obsolete	$0.00	$0.00	$3.54	$0.00	$0.00	$1.90		-	-	25	25	30	$0	$0	$1,062
72	GardCo Bronze - (C) Only	MV	175-watt	66	Obsolete	$0.00	$0.00	$7.79	$0.00	$0.00	$4.18		-	-	99	99	66	$0	$0	$9,255
74	Acrylic Sphere - (C) Only	MV	400-watt	147	Obsolete	$0.00	$0.00	$17.36	$0.00	$0.00	$0.00		-	-	-	0	147	$0	$0	$0
25	Post-Top - Black	HPS	70-watt	30	Obsolete	$5.16	$1.50	$3.54	$7.06	$3.40	$1.90		1,473	821	5	2,299	30	$91,208	$14,778	$97,662
43	Rect.Type - (C) Only	HPS	200-watt	79	Obsolete	$0.00	$0.00	$9.33	$0.00	$0.00	$5.01		-	-	18	18	79	$0	$0	$2,015
5	Incand. - (C) Only	IND	92-watt	31	Obsolete	$0.00	$0.00	$3.66	$0.00	$0.00	$1.96		-	-	25	25	31	$0	$0	$1,098
6	Incand. - (C) Only	IND	182-watt	62	Obsolete	$0.00	$0.00	$7.32	$0.00	$0.00	$3.93		-	-	4	4	62	$0	$0	$351
29	Town and Country Post-Top	MV	175-watt	66	Obsolete	$5.17	$1.51	$7.79	$9.35	$5.69	$4.18		79	747	7	833	66	$4,901	$13,536	$77,869
27	Flood	HPS	70-watt	30	Obsolete	$4.76	$1.42	$3.54	$6.66	$3.32	$0.00		1	-	-	1	30	$57	$0	$42
30	Flood	HPS	100-watt	43	Obsolete	$4.74	$1.52	$5.08	$7.47	$4.25	$2.73		46	5	2	53	43	$2,616	$91	$3,231
38	Flood	HPS	200-watt	79	Obsolete	$5.93	$1.64	$9.33	$10.94	$6.65	$5.01		169	8	4	181	79	$12,026	$157	$20,265
41	Cobrahead - PD	HPS	310-watt	124	Obsolete	$5.96	$1.92	$14.64	$13.82	$9.78	$7.86		5	-	1	6	124	$358	$0	$1,054
14	Ornamental - (C) Only	HPS	100-watt	43	Obsolete	$0.00	$0.00	$5.08	$0.00	$0.00	$2.73		-	-	308	308	43	$0	$0	$18,776
15	Twin Ornamental -(C) Only	HPS	Twin 100-watt	86	Obsolete	$0.00	$0.00	$10.15	$0.00	$0.00	$5.45		-	-	16	16	86	$0	$0	$1,949
7	Flourescent - (C) Only	FLR	28-watt	12	Obsolete	$0.00	$0.00	$1.42	$0.00	$0.00	$0.76		-	-	9	9	12	$0	$0	$153
100	Cobrahead	LED	37-watt	13	Standard	$2.85	$0.00	$1.53	$3.67	$0.00	$0.00		1,604	-	-	1,604	13	$54,857	$0	$29,449
101	Cobrahead	LED	50-watt	17	Standard	$2.82	$0.00	$2.01	$3.90	$0.00	$0.00		24,446	-	-	24,446	17	$827,253	$0	$589,638
102	Cobrahead	LED	52-watt	18	Standard	$3.17	$0.00	$2.13	$4.31	$0.00	$0.00		2,102	-	-	2,102	18	$79,960	$0	$53,727
103	Cobrahead	LED	67-watt	23	Standard	$3.33	$0.00	$2.72	$4.79	$0.00	$0.00		5,157	-	-	5,157	23	$206,074	$0	$168,324
104	Cobrahead	LED	106-watt	36	Standard	$3.62	$0.00	$4.25	$5.90	$0.00	$0.00		1,605	-	-	1,605	36	$69,721	$0	$81,855
105	Cobrahead	LED	134-watt	46	Standard	$7.15	$0.00	$5.43	$10.07	$0.00	$0.00		26	-	-	26	46	$2,231	$0	$1,694
106	Cobrahead	LED	156-watt	53	Standard	$7.65	$0.00	$6.26	$11.01	$0.00	$0.00		84	-	-	84	53	$7,711	$0	$6,310
107	Cobrahead	LED	176-watt	60	Standard	$8.54	$0.00	$7.08	$12.34	$0.00	$0.00		210	-	-	210	60	$21,521	$0	$17,842
108	Cobrahead	LED	201-watt	69	Standard	$8.03	$0.00	$8.15	$12.40	$0.00	$0.00		118	-	-	118	69	$11,370	$0	$11,540
110	Acorn	LED	60-watt	21	Custom	$10.87	$0.00	$2.48	$12.20	$0.00	$0.00		46	-	-	46	21	$6,000	$0	$1,369
111	Acorn	LED	70-watt	24	Custom	$11.79	$0.00	$2.83	$13.31	$0.00	$0.00		54	-	-	54	24	$7,640	$0	$1,834
112	Westbrooke (non-fluted)	LED	53-watt	18	Custom	$15.84	$0.00	$2.13	$16.98	$0.00	$0.00		20	-	-	20	18	$3,802	$0	$511
113	Westbrooke (non-fluted)	LED	69-watt	24	Custom	$15.10	$0.00	$2.83	$16.62	$0.00	$0.00		-	-	-	0	24	$0	$0	$0
114	Westbrooke (non-fluted)	LED	85-watt	29	Custom	$15.73	$0.00	$3.42	$17.57	$0.00	$0.00		1	-	-	1	29	$189	$0	$41
115	Westbrooke (non-fluted)	LED	136-watt	46	Custom	$17.32	$0.00	$5.43	$20.24	$0.00	$0.00		-	-	-	0	46	$0	$0	$0

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Lum				Monthly		Tariff Rates		Monthly	DAX Sch 91 & 95 A & B RATES				Proposed Sch 91 & 95 A & B Counts				Annual	Annual Fixed Revenue		Annual
CODE	Light Description	Type	Watts	kWh	Category	A	B	Energy	A	B	C	TOTAL	A	B	C	TOTAL	MWh	A	B	Energy
116	Westbrooke (non-fluted)	LED	206-watt	70	Custom	$17.04	$0.00	$8.26	$21.48	$0.00	$0.00		-	-	-	0	70	$0	$0	$0
117	Westbrooke (fluted)	LED	53-watt	18	Custom	$16.38	$0.00	$2.13	$17.52	$0.00	$0.00		563	-	-	563	18	$110,663	$0	$14,390
118	Westbrooke (fluted)	LED	69-watt	24	Custom	$16.54	$0.00	$2.83	$18.06	$0.00	$0.00		3	-	-	3	24	$595	$0	$102
119	Westbrooke (fluted)	LED	85-watt	29	Custom	$17.26	$0.00	$3.42	$19.10	$0.00	$0.00		-	-	-	0	29	$0	$0	$0
120	Westbrooke (fluted)	LED	136-watt	46	Custom	$16.94	$0.00	$5.43	$19.86	$0.00	$0.00		-	-	-	0	46	$0	$0	$0
121	Westbrooke (fluted)	LED	206-watt	70	Custom	$18.32	$0.00	$8.26	$22.76	$0.00	$0.00		-	-	-	0	70	$0	$0	$0
127	Westbrooke (non-flare)	LED	36-watt	12	Custom	$14.56	$0.00	$1.42	$15.32	$0.00	$0.00		-	-	-	0	12	$0	$0	$0
128	Westbrooke (flare)	LED	36-watt	12	Custom	$14.92	$0.00	$1.42	$15.68	$0.00	$0.00		101	-	-	101	12	$18,083	$0	$1,721
129	Post-Top, American Revolution	LED	45-watt	15	Custom	$6.88	$0.00	$1.77	$7.83	$0.00	$0.00		16	-	-	16	15	$1,321	$0	$340
130	Post-Top, American Revolution	LED	72-watt	25	Custom	$6.38	$0.00	$2.95	$7.96	$0.00	$0.00		5	-	-	5	25	$383	$0	$177
131	HADCO Acorn	LED	70-watt	24	Custom	$15.43	$0.00	$2.83	$16.95	$0.00	$0.00		247	-	-	247	24	$45,735	$0	$8,388
148	20 - 25	LED		8		$0.00	$0.00	$0.94	$0.00	$0.00	$0.51		-	-	54	54	8	$0	$0	$609
149	>25 - 30	LED		9		$0.00	$0.00	$1.06	$0.00	$0.00	$0.57		-	-	34,769	34,769	9	$0	$0	$442,262
150	>30 - 35	LED		11		$0.00	$0.00	$1.30	$0.00	$0.00	$0.70		-	-	1,412	1,412	11	$0	$0	$22,027
151	>35 - 40	LED		13		$0.00	$0.00	$1.53	$0.00	$0.00	$0.82		-	-	6,383	6,383	13	$0	$0	$117,192
152	>40 - 45	LED		15		$0.00	$0.00	$1.77	$0.00	$0.00	$0.95		-	-	3,943	3,943	15	$0	$0	$83,749
153	>45 - 50	LED		16		$0.00	$0.00	$1.89	$0.00	$0.00	$1.01		-	-	1,568	1,568	16	$0	$0	$35,562
154	>50 - 55	LED		18		$0.00	$0.00	$2.13	$0.00	$0.00	$1.14		-	-	6,558	6,558	18	$0	$0	$167,622
155	>55 - 60	LED		20		$0.00	$0.00	$2.36	$0.00	$0.00	$1.27		-	-	167	167	20	$0	$0	$4,729
156	>60 - 65	LED		21		$0.00	$0.00	$2.48	$0.00	$0.00	$1.33		-	-	8,146	8,146	21	$0	$0	$242,425
157	>65 - 70	LED		23		$0.00	$0.00	$2.72	$0.00	$0.00	$1.46		-	-	516	516	23	$0	$0	$16,842
158	>70 - 75	LED		25		$0.00	$0.00	$2.95	$0.00	$0.00	$1.58		-	-	1,217	1,217	25	$0	$0	$43,082
159	>75 - 80	LED		26		$0.00	$0.00	$3.07	$0.00	$0.00	$1.65		-	-	19	19	26	$0	$0	$700
160	>80 - 85	LED		28		$0.00	$0.00	$3.31	$0.00	$0.00	$1.77		-	-	2,353	2,353	28	$0	$0	$93,461
161	>85 - 90	LED		30		$0.00	$0.00	$3.54	$0.00	$0.00	$1.90		-	-	4,012	4,012	30	$0	$0	$170,430
162	>90 - 95	LED		32		$0.00	$0.00	$3.78	$0.00	$0.00	$2.03		-	-	-	0	32	$0	$0	$0
163	>95 - 100	LED		33		$0.00	$0.00	$3.90	$0.00	$0.00	$2.09		-	-	45	45	33	$0	$0	$2,106
164	>100 - 110	LED		36		$0.00	$0.00	$4.25	$0.00	$0.00	$2.28		-	-	1,808	1,808	36	$0	$0	$92,208
165	>110 - 120	LED		39		$0.00	$0.00	$4.60	$0.00	$0.00	$2.47		-	-	1	1	39	$0	$0	$55
166	>120 - 130	LED		43		$0.00	$0.00	$5.08	$0.00	$0.00	$2.73		-	-	20	20	43	$0	$0	$1,219
167	>130 - 140	LED		46		$0.00	$0.00	$5.43	$0.00	$0.00	$2.92		-	-	2,750	2,750	46	$0	$0	$179,190
168	>140 - 150	LED		50		$0.00	$0.00	$5.90	$0.00	$0.00	$3.17		-	-	13	13	50	$0	$0	$920
169	>150 - 160	LED		53		$0.00	$0.00	$6.26	$0.00	$0.00	$3.36		-	-	1,027	1,027	53	$0	$0	$77,148
170	>160 - 170	LED		56		$0.00	$0.00	$6.61	$0.00	$0.00	$3.55		-	-	157	157	56	$0	$0	$12,453
171	>170 - 180	LED		60		$0.00	$0.00	$7.08	$0.00	$0.00	$3.80		-	-	128	128	60	$0	$0	$10,875
172	>180 - 190	LED		63		$0.00	$0.00	$7.44	$0.00	$0.00	$3.99		-	-	1,000	1,000	63	$0	$0	$89,280
173	>190 - 200	LED		67		$0.00	$0.00	$7.91	$0.00	$0.00	$4.25		-	-	53	53	67	$0	$0	$5,031
174	>200 - 210	LED		70		$0.00	$0.00	$8.26	$0.00	$0.00	$4.44		-	-	18	18	70	$0	$0	$1,784
175	>210 - 220	LED		73		$0.00	$0.00	$8.62	$0.00	$0.00	$4.63		-	-	2	2	73	$0	$0	$207
176	>220 - 230	LED		77		$0.00	$0.00	$9.09	$0.00	$0.00	$4.88		-	-	922	922	77	$0	$0	$100,572
177	>230 - 240	LED		80		$0.00	$0.00	$9.45	$0.00	$0.00	$5.07		-	-	-	0	80	$0	$0	$0
178	>240 - 250	LED		84		$0.00	$0.00	$9.92	$0.00	$0.00	$5.32		-	-	372	372	84	$0	$0	$44,283
179	>250 - 260	LED		87		$0.00	$0.00	$10.27	$0.00	$0.00	$5.51		-	-	-	0	87	$0	$0	$0
180	>260 - 270	LED		91		$0.00	$0.00	$10.74	$0.00	$0.00	$5.77		-	-	-	0	91	$0	$0	$0
181	>270 - 280	LED		94		$0.00	$0.00	$11.10	$0.00	$0.00	$5.96		-	-	17	17	94	$0	$0	$2,264
182	>280 - 290	LED		97		$0.00	$0.00	$11.45	$0.00	$0.00	$6.15		-	-	-	0	97	$0	$0	$0
183	>290 - 300	LED		101		$0.00	$0.00	$11.93	$0.00	$0.00	$6.40		-	-	-	0	101	$0	$0	$0
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								Totals					**46,546**	**21,166**	**88,095**	**155,807**	**9,376**	**$2,243,891**	**$432,286**	**$6,315,343**

Notes:
1. Obsolete fixtures are not available to new service
2. Option C are customer owned and maintained and only pay the respective energy charge

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
57	Black	Fiberglass	20	A	$4.79	5,104	$293,378
59	Bronze	Fiberglass	30	A	$7.43	2,657	$236,898
61	Gray	Fiberglass	30	A	$8.05	5,808	$561,053
1	Standard	Wood	30 to 35	A	$5.28	1,271	$80,531
3	Standard	Wood	40 to 55	A	$6.27	190	$14,296
58	Black	Fiberglass	20	B	$0.15	4,546	$8,183
60	Bronze	Fiberglass	30	B	$0.24	4,536	$13,064
62	Gray	Fiberglass	30	B	$0.26	4,900	$15,288
46	Standard	Wood	30 to 35	B	$0.17	46	$94
47	Standard	Wood	40 to 55	B	$0.20	41	$98
31	Regular	Aluminum	16	A	$6.47	565	$43,867
32	Regular	Aluminum	25	A	$10.65	3,476	$444,233
33	Regular	Aluminum	30	A	$11.44	262	$35,967
28	Regular	Aluminum	35	A	$12.71	79	$12,049
18	Davit	Aluminum	25	A	$10.69	53	$6,799
6	Davit	Aluminum	30	A	$11.26	422	$57,021
29	Davit	Aluminum	35	A	$12.40	636	$94,637
70	Davit with 8-foot Arm	Aluminum	40	A	$16.31	37	$7,242
27	Double Davit	Aluminum	30	A	$15.36	24	$4,424
65	Fluted Victorian Ornamental	Aluminum	14	A	$9.57	115	$13,207
69	Non-fluted Techtra Ornamental	Aluminum	18	A	$19.82	541	$128,671
66	Fluted Ornamental	Aluminum	16	A	$10.32	324	$40,124
77	HADCO Non-fluted Ornamental	Aluminum	16	A	$0.00	0	$0
79	Fluted Westbrooke	Aluminum	18	A	$19.18	72	$16,572
81	Non-fluted Westbrooke	Aluminum	18	A	$19.77	780	$185,047
85	Decorative Ameron	Concrete	20	A	$0.00	0	$0
4	Ameron Post Top	Concrete	25	A	$0.00	0	$0
63	Fluted Ornamental -Black	Fiberglass	14	A	$11.10	667	$88,844
83	Smooth	Fiberglass	18	A	$5.04	2	$121
67	Regular - Color may vary	Fiberglass	22	A	$4.21	18	$909
68	Regular - Color may vary	Fiberglass	35	A	$7.50	424	$38,160
16	Anchor Base -Gray	Fiberglass	35	A	$13.02	51	$7,968
35	Direct Bury with Shroud	Fiberglass	18	A	$7.59	6	$546
34	Regular	Aluminum	16	B	$0.21	52	$131
8	Regular	Aluminum	25	B	$0.34	786	$3,207
48	Regular	Aluminum	30	B	$0.37	464	$2,060
54	Regular	Aluminum	35	B	$0.41	400	$1,968
13	Davit	Aluminum	25	B	$0.34	133	$543
12	Davit	Aluminum	30	B	$0.36	701	$3,028
53	Davit	Aluminum	35	B	$0.40	1,087	$5,218
76	Davit with 8-foot Arm	Aluminum	40	B	$0.52	161	$1,005
14	Double Davit	Aluminum	30	B	$0.49	46	$270
71	Fluted Victorian Ornamental	Aluminum	14	B	$0.31	1,060	$3,943
75	Non-fluted Techtra Ornamental	Aluminum	18	B	$0.63	405	$3,062
72	Fluted Ornamental	Aluminum	16	B	$0.33	1,160	$4,594
78	HADCO Non-fluted Ornamental	Aluminum	16	B	$0.00	0	$0

PORTLAND GENERAL ELECTRIC

Schedule 91 Poles, Forecasted Revenue at Proposed Prices

Pole CODE	Pole Description	Material	Pole Height	Option	Tariff Rates	Counts	Annual Revenues
80	Fluted Westbrooke	Aluminum	18	B	$0.61	367	$2,686
82	Non-fluted Westbrooke	Aluminum	18	B	$0.63	131	$990
44	Painted Ornamental - Portland Rd.	Aluminum	35	B	$0.00	0	$0
86	Decorative Ameron	Concrete	20	B	$0.00	0	$0
5	Ameron Post Top	Concrete	25	B	$0.00	3	$0
64	Fluted Ornamental -Black	Fiberglass	14	B	$0.35	1,502	$6,308
84	Smooth	Fiberglass	18	B	$0.16	1	$2
73	Regular - Color may vary	Fiberglass	22	B	$0.13	421	$657
74	Regular - Color may vary	Fiberglass	35	B	$0.24	577	$1,662
17	Anchor Base -Gray	Fiberglass	35	B	$0.42	58	$292
36	Direct Bury with Shroud	Fiberglass	18	B	$0.24	354	$1,020
2	Post	Aluminum	30	A	$6.47	356	$27,640
30	Ornamental Post	Concrete	35 or less	A	$10.65	57	$7,285
37	Painted Regular	Steel	25	A	$10.65	294	$37,573
38	Painted Regular	Steel	30	A	$11.44	146	$20,043
39	Laminated without Mast Arm	Wood	20	A	$4.79	15	$862
24	Laminted SLO Pole	Wood	20	A	$4.79	3	$172
41	Curved laminated	Wood	30	A	$3.25	0	$0
11	Painted Underground	Wood	35	A	$5.28	24	$1,521
55	Bronze Alloy GardCo	Bronze	12	B	$0.19	0	$0
25	Ornamental Post	Concrete	35 or less	B	$0.34	0	$0
7	Painted Regular	Steel	25	B	$0.34	118	$481
49	Painted Regular	Steel	30	B	$0.37	19	$84
21	Unpainted with 6-foot Mast Arm	Steel	30	B	$0.36	0	$0
51	Unpainted with 6-foot Davit Arm	Steel	30	B	$0.36	0	$0
40	Unpainted with 8-foot Mast Arm	Steel	35	B	$0.40	3	$14
42	Unpainted with 8-foot Davit Arm	Steel	35	B	$0.40	0	$0
23	Laminated without Mast Arm	Wood	20	B	$0.15	1,456	$2,621
45	Curved laminated	Wood	30	B	$0.24	96	$276
26	Painted Underground	Wood	35	B	$0.17	43	$88
				Total Option As		24,479	$2,507,659
				Total Option Bs		25,673	$82,938
						50,152	$2,590,596

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

Code	Description	Type	Size	kWh	Monthly Tariff Price Fixed	Energy	Total	DAX Monthly Tariff Price Fixed	Energy	Total	Count	Annual MWh	Revenues Fixed	Energy	Total
Fixtures															
21	Cobrahead	MV	175-watt	66	$4.73	$7.79	$12.52	$4.73	$4.18	$8.91	318	252	$18,050	$29,727	$47,776
23	Cobrahead	MV	400-watt	147	$5.27	$17.36	$22.63	$5.27	$9.32	$14.59	1,684	2,971	$106,496	$350,811	$457,307
24	Cobrahead	MV	1000-watt	374	$5.50	$44.16	$49.66	$5.50	$23.70	$29.20	73	328	$4,818	$38,684	$43,502
33	Cobrahead - (non-pd)	HPS	70-watt	30	$4.77	$3.54	$8.31	$4.77	$1.90	$6.67	128	46	$7,327	$5,437	$12,764
34	Cobrahead - (non-pd)	HPS	100-watt	43	$4.77	$5.08	$9.85	$4.77	$2.73	$7.50	62	32	$3,549	$3,780	$7,328
35	Cobrahead - (non-pd)	HPS	150-watt	62	$4.88	$7.32	$12.20	$4.88	$3.93	$8.81	11	8	$644	$966	$1,610
39	Cobrahead - (non-pd)	HPS	200-watt	79	$5.26	$9.33	$14.59	$5.26	$5.01	$10.27	30	28	$1,894	$3,359	$5,252
36	Cobrahead - (non-pd)	HPS	250-watt	102	$5.14	$12.04	$17.18	$5.14	$6.46	$11.60	38	47	$2,344	$5,490	$7,834
41	Cobrahead - (PD)	HPS	310-watt	124	$5.50	$14.64	$20.14	$5.50	$7.86	$13.36	6	9	$396	$1,054	$1,450
37	Cobrahead - (non-pd)	HPS	400-watt	163	$5.21	$19.25	$24.46	$5.21	$10.33	$15.54	1,322	2,586	$82,651	$305,382	$388,033
30	Flood	HPS	100-watt	43	$4.66	$5.08	$9.74	$4.66	$2.73	$7.39	385	199	$21,529	$23,470	$44,999
38	Flood	HPS	200-watt	79	$5.47	$9.33	$14.80	$5.47	$5.01	$10.48	674	639	$44,241	$75,461	$119,702
31	Flood	HPS	250-watt	102	$5.43	$12.04	$17.47	$5.43	$6.46	$11.89	786	962	$51,216	$113,561	$164,777
32	Flood	HPS	400-watt	163	$5.43	$19.25	$24.68	$5.43	$10.33	$15.76	1,758	3,439	$114,551	$406,098	$520,649
76	Shoebox	HPS	70-watt	30	$6.08	$3.54	$9.62	$6.08	$1.90	$7.98	10	4	$730	$425	$1,154
77	Shoebox	HPS	100-watt	43	$5.77	$5.08	$10.85	$5.77	$2.73	$8.50	532	275	$36,836	$32,431	$69,266
78	Shoebox	HPS	150-watt	62	$6.09	$7.32	$13.41	$6.09	$3.93	$10.02	100	74	$7,308	$8,784	$16,092
81	Special Acorn	HPS	100-watt	43	$8.02	$5.08	$13.10	$8.02	$2.73	$10.75	343	177	$33,010	$20,909	$53,920
82	HADCO - Victorian	HPS	150-watt	62	$8.02	$7.32	$15.34	$8.02	$3.93	$11.95	21	16	$2,021	$1,845	$3,866
49	HADCO - Victorian	HPS	200-watt	79	$8.68	$9.33	$18.01	$8.68	$5.01	$13.69	2	2	$208	$224	$432
83	HADCO - Victorian	HPS	250-watt	102	$8.68	$12.04	$20.72	$8.68	$6.46	$15.14	0	0	$0	$0	$0
40	Early American Post-Top	HPS	100-watt	43	$5.15	$5.08	$10.23	$5.15	$2.73	$7.88	160	83	$9,888	$9,754	$19,642
62	Cobrahead	MH	150-watt	60	$5.30	$7.08	$12.38	$5.30	$3.80	$9.10	12	9	$763	$1,020	$1,783
48	Cobrahead	MH	175-watt	71	$5.37	$8.38	$13.75	$5.37	$4.50	$9.87	0	0	$0	$0	$0
61	Flood	MH	350-watt	139	$5.45	$16.41	$21.86	$5.45	$8.81	$14.26	362	604	$23,675	$71,285	$94,960
60	Flood	MH	400-watt	156	$5.63	$18.42	$24.05	$5.63	$9.89	$15.52	14	26	$946	$3,095	$4,040
47	Flood	HPS	750-watt	285	$8.63	$33.65	$42.28	$8.63	$18.06	$26.69	113	386	$11,702	$45,629	$57,332
12	HADCO Independence	HPS	100-watt	43	$8.17	$5.08	$13.25	$8.17	$2.73	$10.90	19	10	$1,863	$1,158	$3,021
13	HADCO Independence	HPS	150-watt	62	$8.17	$7.32	$15.49	$8.17	$3.93	$12.10	4	3	$392	$351	$744
64	HADCO Capitol Acorn	HPS	100-watt	43	$11.60	$5.08	$16.68	$11.60	$2.73	$14.33	9	5	$1,253	$549	$1,801
67	HADCO Capitol Acorn	HPS	150-watt	62	$10.33	$7.32	$17.65	$10.33	$3.93	$14.26	0	0	$0	$0	$0
65	HADCO Capitol Acorn	HPS	200-watt	79	$10.35	$9.33	$19.68	$10.35	$5.01	$15.36	0	0	$0	$0	$0
66	HADCO Capitol Acorn	HPS	250-watt	102	$10.33	$12.04	$22.37	$10.33	$6.46	$16.79	0	0	$0	$0	$0
98	HADCO Techtra	HPS	100-watt	43	$16.48	$5.08	$21.56	$16.48	$2.73	$19.21	0	0	$0	$0	$0
99	HADCO Techtra	HPS	150-watt	62	$16.26	$7.32	$23.58	$16.26	$3.93	$20.19	2	1	$390	$176	$566
88	HADCO Techtra	HPS	250-watt	102	$16.09	$12.04	$28.13	$16.09	$6.46	$22.55	0	0	$0	$0	$0
90	HADCO Westbrooke	HPS	70-watt	30	$10.55	$3.54	$14.09	$10.55	$1.90	$12.45	0	0	$0	$0	$0
91	HADCO Westbrooke	HPS	100-watt	43	$10.13	$5.08	$15.21	$10.13	$2.73	$12.86	0	0	$0	$0	$0
92	HADCO Westbrooke	HPS	150-watt	62	$14.66	$7.32	$21.98	$14.66	$3.93	$18.59	0	0	$0	$0	$0
93	HADCO Westbrooke	HPS	200-watt	79	$10.31	$9.33	$19.64	$10.31	$5.01	$15.32	0	0	$0	$0	$0
94	HADCO Westbrooke	HPS	250-watt	102	$10.88	$12.04	$22.92	$10.88	$6.46	$17.34	0	0	$0	$0	$0
9	Holophane Mongoose	HPS	150-watt	62	$8.40	$7.32	$15.72	$8.40	$3.93	$12.33	0	0	$0	$0	$0
100	Cobrahead	LED	37-watt	13	$3.20	$1.53	$4.73	$3.20	$0.82	$4.02	24	4	$922	$441	$1,362
101	Cobrahead	LED	50-watt	17	$3.17	$2.01	$5.18	$3.17	$1.08	$4.25	224	46	$8,521	$5,403	$13,924
102	Cobrahead	LED	52-watt	18	$3.52	$2.13	$5.65	$3.52	$1.14	$4.66	71	15	$2,999	$1,815	$4,814
103	Cobrahead	LED	67-watt	23	$3.56	$2.72	$6.28	$3.56	$1.46	$5.02	70	19	$2,990	$2,285	$5,275
104	Cobrahead	LED	106-watt	36	$3.85	$4.25	$8.10	$3.85	$2.28	$6.13	103	44	$4,759	$5,253	$10,012
105	Cobrahead	LED	134-watt	46	$6.69	$5.43	$12.12	$6.69	$2.92	$9.61	23	13	$1,846	$1,499	$3,345
106	Cobrahead	LED	156-watt	53	$7.20	$6.26	$13.46	$7.20	$3.36	$10.56	29	18	$2,506	$2,178	$4,684
107	Cobrahead	LED	176-watt	60	$8.08	$7.08	$15.16	$8.08	$3.80	$11.88	28	20	$2,715	$2,379	$5,094
108	Cobrahead	LED	201-watt	69	$7.58	$8.15	$15.73	$7.58	$4.37	$11.95	204	169	$18,556	$19,951	$38,507
110	Acorn	LED	60-watt	21	$10.41	$2.48	$12.89	$10.41	$1.33	$11.74	15	4	$1,874	$446	$2,320
111	Acorn	LED	70-watt	24	$11.34	$2.83	$14.17	$11.34	$1.52	$12.86	5	1	$680	$170	$850
112	Westbrooke (non-flare)	LED	53-watt	18	$15.38	$2.13	$17.51	$15.38	$1.14	$16.52	0	0	$0	$0	$0
113	Westbrooke (non-flare)	LED	69-watt	24	$14.64	$2.83	$17.47	$14.64	$1.52	$16.16	0	0	$0	$0	$0

PORTLAND GENERAL ELECTRIC
Schedule 15, Proposed Tariff Prices, Counts and Revenue

						Monthly Tariff Price		DAX Monthly Tariff Price				Annual		Revenues	
Code	**Description**	**Type**	**Size**	**kWh**	**Fixed**	**Energy**	**Total**	**Fixed**	**Energy**	**Total**	**Count**	**MWh**	**Fixed**	**Energy**	**Total**
114	Westbrooke (non-flare)	LED	85-watt	29	$15.27	$3.42	$18.69	$15.27	$1.84	$17.11	0	0	$0	$0	$0
115	Westbrooke (non-flare)	LED	136-watt	46	$16.86	$5.43	$22.29	$16.86	$2.92	$19.78	0	0	$0	$0	$0
116	Westbrooke (non-flare)	LED	206-watt	70	$16.58	$8.26	$24.84	$16.58	$4.44	$21.02	0	0	$0	$0	$0
117	Westbrooke (flare)	LED	53-watt	18	$15.93	$2.13	$18.06	$15.93	$1.14	$17.07	0	0	$0	$0	$0
118	Westbrooke (flare)	LED	69-watt	24	$16.08	$2.83	$18.91	$16.08	$1.52	$17.60	0	0	$0	$0	$0
119	Westbrooke (flare)	LED	85-watt	29	$16.80	$3.42	$20.22	$16.80	$1.84	$18.64	0	0	$0	$0	$0
120	Westbrooke (flare)	LED	136-watt	46	$16.48	$5.43	$21.91	$16.48	$2.92	$19.40	0	0	$0	$0	$0
121	Westbrooke (flare)	LED	206-watt	70	$17.86	$8.26	$26.12	$17.86	$4.44	$22.30	0	0	$0	$0	$0
122	CREE XSP	LED	25-watt	9	$2.30	$1.06	$3.36	$2.30	$0.57	$2.87	911	98	$25,144	$11,588	$36,732
123	CREE XSP	LED	42-watt	14	$2.39	$1.65	$4.04	$2.39	$0.89	$3.28	5,883	988	$168,724	$116,483	$285,208
124	CREE XSP	LED	48-watt	16	$2.79	$1.89	$4.68	$2.79	$1.01	$3.80	945	181	$31,639	$21,433	$53,071
125	CREE XSP	LED	56-watt	19	$3.22	$2.24	$5.46	$3.22	$1.20	$4.42	2,064	471	$79,753	$55,480	$135,233
126	CREE XSP	LED	91-watt	31	$3.22	$3.66	$6.88	$3.22	$1.96	$5.18	855	318	$33,037	$37,552	$70,589
127	Westbrooke (non-flare)	LED	36-watt	12	$14.10	$1.42	$15.52	$14.10	$0.76	$14.86	0	0	$0	$0	$0
128	Westbrooke (flare)	LED	36-watt	12	$14.46	$1.42	$15.88	$14.46	$0.76	$15.22	0	0	$0	$0	$0
129	Post-Top, American Revolution	LED	45-watt	15	$6.42	$1.77	$8.19	$6.42	$0.95	$7.37	15	3	$1,156	$319	$1,474
130	Post-Top, American Revolution	LED	72-watt	25	$5.92	$2.95	$8.87	$5.92	$1.58	$7.50	0	0	$0	$0	$0
Totals											20,447	15,632	$978,511	$1,845,587	$2,824,098

Poles						
1	Standard	Wood	30 to 35	$5.18	6,141	$381,725
3	Standard	Wood	40 to 55	$6.17	636	$47,089
11	Painted Underground	Wood	35	$5.18	6	$373
41	Curved laminated	Wood	30	$6.51	0	$0
31	Regular	Aluminum	16	$6.39	11	$843
32	Regular	Aluminum	25	$10.52	11	$1,389
33	Regular	Aluminum	30	$11.31	18	$2,443
28	Regular	Aluminum	35	$12.59	3	$453
65	Fluted Ornamental	Aluminum	14	$9.50	29	$3,306
18	Davit	Aluminum	25	$10.57	0	$0
6	Davit	Aluminum	30	$11.13	16	$2,137
29	Davit	Aluminum	35	$12.28	0	$0
70	Davit with 8-foot Arm	Aluminum	40	$16.15	0	$0
27	Double Davit	Aluminum	30	$15.23	3	$548
66	HADCO, Fluted Ornamental	Aluminum	16	$10.24	2	$246
69	HADCO, Non-fluted Techtra Ornamental	Aluminum	18	$19.69	19	$4,489
4	Ameron Post-Top	Concrete	25	$17.79	0	$0
63	Fluted Ornamental Black	Fiberglass	14	$11.00	169	$22,308
57	Regular Black	Fiberglass	20	$4.72	360	$20,390
61	Regular Gray	Fiberglass	30	$7.92	1,407	$133,721
68	Regular Other Colors	Fiberglass	35	$7.40	41	$3,641
16	Anchor Base Gray	Fiberglass	35	$12.92	2	$310
35	Direct Bury with Shroud	Fiberglass	18	$7.47	115	$10,309
79	Fluted Westbrooke	Aluminum	18	$19.05		
81	Non-Fluted Westbrooke	Aluminum	18	$19.64		
Totals					8,989	$635,721
Totals Luminaires and Poles						$3,459,819

ELLEN F. ROSENBLUM
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

June 6, 2013

Filing Center
Public Utility Commission of Oregon
550 Capitol Street, Suite 215
PO Box 2148
Salem, Oregon 97308

Re: OPUC Docket Nos. UE 215 and UM 1644

Dear Filing Center:

Enclosed for filing in Docket Nos. UM 1644 and UE 215 are two originals and ten copies of "An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123" prepared by Christensen Associated Energy Consulting and dated May 31, 2013 (one original and five copies for each docket). Christensen Associated Energy prepared this evaluation pursuant to Commission Order No. 10-478.

In Portland General Electric Company's ("POE") last general rate case, docketed as Docket No. UE 215, parties to a Stipulation Regarding Remaining Issues" [1] agreed to ask the Commission to extend the termination date of PGE's Schedule 123 decoupling tariffs to December 31, 2013. The stipulating parties also agreed to ask the Commission to order an evaluation of the decoupling mechanism by an independent consultant in 2013. The Commission approved the stipulation and ordered that an independent consultant be hired to evaluate PGE's decoupling mechanism and that the evaluation will include answers to specific questions set forth in stipulation.2 (*See* OPUC Order No. 10-478 at 10.)

On January 11, 2013, the Commission opened an investigation into the evaluation of PGE's decoupling mechanism, which was docketed as Docket No. UM 1644.

[1] The stipulating parties include PGE, Staff, the Citizens' Utility Board, the Industrial Customers of Northwest Utilities, and Fred Meyer Stores and Quality Foods Centers, Division of Kroger ("Kroger").
[2] The questions specified in the parties' stipulation are attached to this letter.

Christensen Associates Energy Consulting forwarded electronic copies of its report to Staff on May 31, 2013. Staff is now filing the report with the Commission in Docket Nos. UM 1644 and Docket No. UE 215 with copies to all parties on both service lists.

Sincerely,

Senior Assistant Attorney General
Business Activities Section

Enclosures
SSA:jrs/#43098 11
(Electronic copies only)
c. UE 215 Service List
UM 1644 Service List

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123

by

Daniel G. Hansen
Robert J. Camfield
Marlies C. Hilbrink

May 31, 2013

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299

Voice 608.231.2266 Fax 608.231.2108

Table of Contents

1. INTRODUCTION AND BACKGROUND

In January 2009, the Oregon Public Utility Commission ("OPUC" or "the Commission") issued Order 09-020 (the "Order"), which approved Schedule 123 for use by Portland General Electric ("PGE"). This schedule contains two components: the Sales Normalization Adjustment ("SNA"), which applies to residential and small commercial customers; and the Lost Revenue Recovery Adjustment ("LRRA"), which applies to larger non-residential customers.[1]

PGE's proposal to adopt the SNA and LRRA was motivated by the fact that a large portion of its fixed costs are recovered through volumetric (i.e., per-kilowatt-hour) rates, so that reductions in energy sales lead to reductions in revenues toward fixed cost recovery. This gives the utility a disincentive to promote conservation and energy efficiency for its customers, as success in these efforts would reduce utility revenues without inducing a corresponding reduction in utility fixed costs.

The proposal met with some resistance from OPUC Staff, Kroger, and the Citizens' Utility Board of Oregon ("CUB"). Arguments against the SNA included:

- It shifts risk from the utility to its ratepayers;
- It is likely to lead to over-collection of fixed cost revenues;
- Because the Energy Trust of Oregon ("ETO") is a third-party administrator of energy efficiency programs, the scope for PGE to affect customer energy efficiency decisions is limited;
- It produces a disincentive for PGE's customers to engage in conservation;
- It shifts economic risk (i.e., the adverse effects of a recession) from PGE to its ratepayers; and
- It is more focused on revenue assurance for the utility than it is on enabling customer conservation.

The Commission largely rejected these arguments in the Order and approved the mechanism, with two significant requirements: that PGE's authorized return on equity ("ROE") be reduced by 10 basis points in order to account for a reduction in utility risk;[2] and that an assessment of the effectiveness of the SNA and LRRA be completed no later than six months prior to schedule's expiration date. This report is intended to meet the latter requirement. The program's initial two-year authorization was extended in 2011. It is now due for re-authorization or cancellation on December 31, 2013.

The report is organized as follows. Section 2 provides descriptions of the SNA and LRRA mechanisms. Section 3 describes the evaluation requirements. Section 4 contains an evaluation of program mechanics. Section 5 considers the effect of Schedule 123 on PGE's risk. Section 6

[1] Non-residential customers with load exceeding one average megawatt (aMW) and Self-Directing customers are exempted from the LRRA.
[2] The Commission ruled that, while the SNA and LRRA do not shift risk from the utility to its ratepayers, they do reduce utility risk.

examines the effect of Schedule 123 on PGE's behavior. Section 7 summarizes the stakeholder interviews. Section 8 describes sources of potential harm from Schedule 123 that were not investigated in the study. Section 9 provides conclusions and recommendations.

2. DESCRIPTIONS OF THE SNA AND LRRA MECHANISMS

This section provides detailed descriptions of each mechanism contained in Schedule 123.

2.1 Sales Normalization Adjustment

The SNA applies to customers served on Schedules 7 (Residential Service), 32 (Small Nonresidential Standard Service), and 532 (Small Nonresidential Direct Access Service). It is a form of revenue per customer decoupling, in which monthly deferrals are based on the difference between *allowed* revenues toward fixed costs and *actual* revenues toward fixed costs (in this case adjusted to represent revenues under normal weather conditions[3]).

The monthly deferral calculation is shown in Equation 1.

Equation 1: $SNA\ Deferral_{m,c} = FCC_c \times Customers_{m,c} - EP^{SNA}_c \times Sales^{WN}_{m,c}$

The terms of the equation are defined in Table 2.1.

Table 2.1: Variables Included in the SNA Deferral Calculation

Variable	Description
$SNA\ Deferral_{m,c}$	The SNA deferral in month *m* for customer class *c*
EP^{SNA}_c	The Fixed Charge Energy Rate (in cents/kWh) for customer group *c*
$Sales^{WN}_{m,c}$	Weather-normalized sales (in kWh) to customer class *c* in month *m*
FCC_c	The Monthly Fixed Charge (in $/customer-month) for customer class *c*
$Customers_{m,c}$	The number of customers in month *m* and customer class *c*

This calculation is made each month, with the resulting value placed in a tracking account called the SNA Balancing Account. A positive value indicates that PGE under-recovered in that month (i.e., allowed revenue was higher than actual revenue). A negative value indicates that PGE over-recovered revenue in that month. Balances in the SNA Balancing Account accrue interest calculated using the Commission-authorized Modified Blended Treasury Rate.

Every twelve months, the balance is recovered from customers (if it is positive) or refunded to customers (if it is negative) through a change to the volumetric rate in the following year. Separate balancing accounts and rate changes are calculated for each schedule. Rate increases due to the SNA Balancing Account cannot exceed 2 percent of net rates on the applicable rate schedule (i.e., 7 or 32). Rate decreases are not subject to the 2 percent limit.

[3] The weather adjustment that converts observed sales into weather-normalized sales is conducted using the same methods used to forecast loads when setting base rates.

It can be useful to restate the SNA deferral calculation in the following way:
Equation 2a: $SNA\ Deferral_{m,c} = Customers_{m,c} \times (FCC_c - EP^{SNA}_c \times SalesPerCust^{WN}_{m,c})$, or
Equation 2b: $SNA\ Deferral_{m,c} = Customers_{m,c} \times (Allowed\ RPC_c - WN\ Actual RPC_{m,c})$

The terms of these equations are defined in Table 2.2.

Table 2.2: Variables Included in the Restated SNA Deferral Calculations

Variable	Description
$SNA\ Deferral_{m,c}$	The SNA deferral in month *m* for customer class *c*
$Customers_{m,c}$	The number of customers in month *m* and customer class *c*
FCC_c	The Monthly Fixed Charge (in $/customer-month) for customer class *c*
EP^{SNA}_c	The Fixed Charge Energy Rate (in cents/kWh) for customer group *c*
$SalesPerCust^{WN}_{m,c}$	Weather-normalized sales per customer (in kWh) to customer class *c* in month *m*
$Allowed\ RPC_c$	SNA allowed revenue per customer for customer group *c*
$WN\ Actual\ RPC_{m,c}$	Weather-normalized actual revenue per customer in month *m* for customer group *c*

Equation 2a is shown only to illustrate the intermediate step taken to derive Equation 2b from Equation 1. Equation 2b shows the SNA deferral in a manner that may make its effects easier to understand and interpret: it is the difference between the revenue per customer allowed under the SNA and the actual revenue per customer (based on weather normalized billed sales), multiplied by the number of customers served in the current month. This formulation of the SNA deferral more clearly shows that deferrals are only created in months when revenue per customer deviates from the "allowed" value.

2.2 Lost Revenue Recovery Adjustment

The LRRA applies to all customers that use less than one aMW except those served on Schedules 7, 32, and 532. It adjusts utility revenues to account for "lost revenues" associated with conservation and energy efficiency programs funded from sources other than Schedule 108 (Public Purpose Charge). Lost revenues are defined as the portion of revenues from volumetric rates that are intended to recover fixed costs (distribution, transmission, and generation).

As with the SNA, the LRRA includes a deferral calculation, which is shown in Equation 3. When PGE's base rates are set, the ETO's forecast of energy savings from energy efficiency and conservation programs is used. (I.e., sales reductions from ETO programs lead to less energy sold by PGE, which will lead to an increase in base rates, all else equal.) The LRRA adjusts utility revenues by reconciling differences between ETO's forecast sales reductions and its *ex post* estimates of sales reductions from its programs.

Equation 3: $LRRA\ Deferral_m = EP^{LRRA} \times (ETO^{Act}_m - ETO^{For}_m)$

The terms of the equation are defined in Table 2.3.

Table 2.3: Variables Included in the LRRA Deferral Calculation

Variable	Description
$LRRA\ Deferral_y$	The LRRA deferral in year *y*
EP^{LRRA}	The Fixed Charge Energy Rate (in cents/kWh)
$ETO^{Act}{}_y$	Energy savings reported by ETO (in kWh) in year *y*
$ETO^{For}{}_y$	ETO's forecast energy savings (in kWh) for year *y* when setting rates

LRRA deferral amounts are placed in a tracking account called the LRRA Balancing Account. A positive value indicates that PGE under-recovered in that year.[4] That is, when ETO's forecast of sales reductions is less than its *ex post* estimates of actual sales reductions, PGE is allowed to recover the difference through a future rate increase. Conversely, when the ETO over-forecasts sales reductions from conservation and energy efficiency programs, PGE refunds the over-recovery to customers through a future rate decrease. Balances in the LRRA Balancing Account accrue interest calculated using the Commission-authorized Modified Blended Treasury Rate.

Each year, the balance is recovered from customers (if it is positive) or refunded to customers (if it is negative) through a change to the volumetric rate in the following year. As with the SNA, rate increases cannot exceed 2 percent of net rates on the applicable rate schedule and rate decreases are not subject to the 2 percent limit. All applicable customers receive the same cent/kWh rate change from the LRRA.

3. EVALUATION REQUIREMENTS

The Order specified six issues to be addressed in the required evaluation of Schedule 123. Subsequent to the Order, meetings of stakeholders produced additions to the list of questions.[5] The final list is shown below.

1. Did the mechanisms effectively remove the relationship between the utility's sales and profits?
2. Did the mechanisms effectively mitigate the utility's disincentives to promote energy efficiency?
3. Did the mechanisms improve the utility's ability to recover its fixed costs?
4. Did the mechanisms reduce business and other financial risks? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.
5. What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanisms? Did the partial decoupling mechanisms affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality?

[4] The deferral amount is assumed to be recovered in equal amounts across the twelve months of the year, which is relevant in the calculation of interest received/paid on the LRRA Balancing Account.
[5] The stakeholders include CUB, ETO, Kroger, Northwest Energy Coalition, OPUC Staff, and PGE.

6. To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in UE 197 and in any subsequent general rate case?
7. PGE's mechanisms are based on a volumetric fixed charge. However, the amount of revenue available for fixed cost recovery may vary depending on the variable cost of the power being sold or purchased (Revenue/kWh minus variable power cost/kWh equals revenue available for fixed costs). Should the volumetric fixed charge decoupling rates be calculated in a different manner in order to account for this? For example, as the difference between total volumetric rates for both Schedules 7 and 32 and a measurement of short-run marginal energy costs such as the Mid-Columbia index?
8. What is the effect of a change in load (as included in these mechanisms) on PGE's costs? What is the effect of the change in load on revenue? Have the mechanisms accurately accounted for these changes? On a going forward basis are the mechanisms likely to accurately account for these changes?
9. Should the SNA mechanism be bifurcated such that the total kWh for each of Schedules 7 and 32 are fixed for and beyond the test period for purposes of recovery/refund of transmission and generation fixed revenue requirements? Calculation of the fixed revenue requirements for functions other than generation and transmission would be in the same manner as is currently done.
10. What is the interaction between the PGE decoupling mechanisms and the recent recession with regard to residential and small nonresidential customers?
11. How often should the fixed costs and use-per-customer parameters be updated?
12. What recommendations to the current PGE decoupling mechanisms would you suggest? Should it continue beyond 2013? Should it be terminated? Should it be modified? If so, what specific modifications should be made?

The remainder of this report consists of five sections. The guide below indicates the section in which each analysis question is addressed.

- Section 4: Questions 1, 2, 3, 6, 7, 8, 9, and 10.
- Section 5: Question 4.
- Section 6: Question 5.
- Section 7: Contribute to all questions.
- Section 8: Questions 11 and 12.

4. PROGRAM MECHANICS

4.1 Review of Program Mechanics

In order to evaluate the SNA and LRRA mechanisms, we reviewed spreadsheets provided by PGE that contain the calculations used to set the parameters (e.g., the SNA's Fixed Energy Charge Rate) and calculate the annual rate changes (via deferrals) attributed to each mechanism.

It may be useful to provide an overview of how the SNA Fixed Charge Energy Rate (FCER) is set, using Schedule 7 (residential customers) as an example.

Sales Normalization Adjustment

Table 4.1.1 contains the components of the FCER (under rates determined in Docket UE-215), showing that distribution and fixed generation are the two largest components, together accounting for 93.5 percent of the total FCER.[6] Because of the importance of these cost categories, we illustrate the derivation of each in Tables 4.1.2 and 4.1.3.

Table 4.1.1 Construction of the SNA Fixed Charge Energy Rate, *Schedule 7*

Cost Category	Fixed Charge Energy Rate (cents/kWh)
Distribution	2.826
Fixed Generation	2.495
Transmission and Ancillary Services	0.235
Generation Rate Design	0.114
Trojan Decommissioning	0.019
Total	**5.689**

Table 4.1.2 illustrates the derivation of the distribution component of the SNA's FCER. Distribution revenue is calculated by subtracting the following from the Schedule 7 required revenue amount: basic service charge revenue (which is already "decoupled" from sales); transmission revenue (which is included as its own component); franchise fees; and energy charge revenue (which is a combination of fixed generation costs, which are their own category, and expected variable fuel costs). The remainder of approximately $215 million is divided by forecast sales to arrive at the fixed distribution charge per kWh (2.826 cents / kWh).

Table 4.1.2 Derivation of the Distribution Component of the SNA, *Schedule 7*

Description	Amount ($000)
Schedule 7 Required Revenue	$858,636
– Basic Service Charge Revenue	$77,930
– Transmission Revenue	$17,861
– Franchise Fees	$22,042
– Energy Charge Revenue	$526,009
= Distribution Revenue	**$214,794**
÷ Forecast Sales, Schedule 7	7,601 MWh
Distribution Component of SNA	**2.826 cents / kWh**

Table 4.1.3 shows the derivation of the fixed generation component of the SNA. It begins with the total of projected production costs across all classes and subtracts forecast net variable power costs, which is the same measure of variable power costs used in PGE's power cost

[6] A parallel exercise could be conducted for the SNA Monthly Fixed Charge per Customer. The shares of total revenue by cost category would be the same as those implied by Table 4.1.1.

adjustment schedules (125 and 126). The remainder is presumed to represent the fixed generation revenue requirement in total, a portion of which is allocated to Schedule 7. The allocation factor is based on estimates of marginal energy and capacity costs, and results in 45.06 percent of fixed generation costs being allocated to Schedule 7.[7] The amount of approximately $190 million is divided by forecast sales to obtain fixed generation cost stated on a kWh basis.

Table 4.1.3 Derivation of the Fixed Generation Component of the SNA, *Schedule 7*

Description	Amount ($000)
Total Production Costs	$1,148,599
– Net Variable Power Costs	$727,762
= Fixed Generation Revenue Requirement	$420,837
x Capacity and Energy Allocator, Schedule 7	45.06%
= Fixed Generation Revenue Requirement, Schedule 7	$189,619
÷ Forecast Sales, Schedule 7	7,601 MWh
Fixed Generation Component	**2.495 cents / kWh**

Lost Revenue Recovery Adjustment

For the LRRA, it is instructive to demonstrate how the share of lost revenues (by cost component) is determined, using Schedule 83-S (large non-residential standard service for secondary customers with peak demand between 31 and 200 kW) as an example. Table 4.1.4 shows that distribution and fixed generation costs constitute the majority of the charge, which was also the case with the SNA.

Table 4.1.4 LRRA Lost Revenue by Cost Category, *Schedule 83-S*

Cost Category	Lost Revenue (cents/kWh)
Transmission and ancillary services	0.25
Distribution	1.78
Fixed generation[8]	2.28
Total	**4.32**

The LRRA is applicable to a wide range of customer classes, from small volume lighting schedules (e.g., Schedule 15) to primary service for large customers (Schedule 89-P). Expressed in cents per kWh, Table 4.1.5 shows the lost revenues calculated by PGE for each of the applicable rate schedules. Notice the wide range of charges, from a low of 3.17 cents/kWh to a high of 13.70 cents/kWh. While the range seems substantially smaller once one focuses on the schedules with the majority of the sales, significant differences remain. For example, the lost revenue rate for Schedule 83-S is 36 percent higher than the rate for Schedule 89-P.

[7] Marginal capacity costs are based on an assume $191.18 per kW simple cycle plant multiplied by PGE's projected peak load. The total cost is allocated to individual customer classes using a 4-CP allocator.
[8] Sales for direct access customers are removed in the calculation of the fixed generation component.

Because all applicable rate schedules receive the same LRRA adjustment charge (3.93 cents/kWh), the differences in lost revenues per kWh across rate schedules has led to some concerns that the LRRA leads to cross-subsidies. The information shown in Table 4.1.5 provides support for those concerns. However, there may be substantial administrative costs associated with rectifying the situation. In order to mitigate the potential for cross-subsidies to be introduced by the LRRA, the ETO would need to calculate conservation savings for each of PGE's LRRA-applicable rate schedules. Each schedule's lost revenue charge could then be applied to its own conservation-induced sales reductions to determine the total lost revenues by rate schedule.

If this remedy is not feasible or institutionally desirable (e.g., high administrative costs that outweigh the benefits), an intermediate solution is possible. That is, each LRRA-applicable rate schedule could be assigned a share of the ETO-measured conservation (perhaps based on total sales shares, as shown in the rightmost column of Table 4.1.5) and recovered at the schedule-specific lost revenue rates. This would *not* remove cross-subsidies due to differing levels of conservation across schedules, but it would mitigate cross-subsidies due to the application of a single LRRA charge across all rate schedules.

Table 4.1.5 LRRA Lost Revenue by Rate Schedule

Rate Schedule	Description	Lost Revenue (cents/kWh)	MWh Sales	Share of Sales
15	Outdoor area lighting	5.10	23,857	0.3%
38	Large non-res. TOD	7.66	33,511	0.5%
47	Small non-res irrigation	6.80	23,080	0.3%
49	Large non-res irrigation	4.77	67,653	1.0%
91	Street & highway lighting	5.16	108,227	1.6%
92	Traffic signals	4.11	4,733	0.1%
93	Recreational field lighting	13.70	576	0.0%
83-S	Large non-res, 31-200kW	4.32	2,771,767	40.0%
85-S	Large non-res, 201-1,000kW	3.69	2,340,481	33.8%
85-P	Large non-res, 201-1,000kW	3.47	289,091	4.2%
89-S	Large non-res, >1,000kW	3.39	561,706	8.1%
89-P	Large non-res, >1,000kW	3.17	697,704	10.1%
Total		**3.93**	**6,922,385**	**100.0%**

Schedule 123 Deferrals to Date

Table 4.1.6 contains the annual deferral amounts by year for each of the three parts of Schedule 123: the SNA for Schedule 7; the SNA for Schedule 32; and the LRRA. A positive number indicates utility under-recovery, leading to a surcharge on customer bills in the following year.

Across all years and customer groups, the net effect of Schedule 123 has been to increase utility revenues by approximately $576,000. The net effects vary across customer groups. Residential (Schedule 7) customers received surcharges in three of the four years, with a net effect of approximately $3.2 million across the four years. The experience so far has been mixed for the small commercial (Schedule 32) customers. The large commercial and industrial customers received rate reductions in three of the four years, with a net revenue refund of approximately $1.9 million. The result implies that the ETO estimates of conservation that have been incorporated within base rates tend to over-state the amount of conservation that ETO estimated after the fact, so that the lost revenues for the LRRA-applicable rate schedules were lower than expected.

Table 4.1.6 Schedule 123 Deferrals by Year ($000)

Year	SNA Schedule 7	SNA Schedule 32	LRRA	Total
2009	-$3,652	$1,829	-$1,072	-$2,895
2010	$3,873	$2,266	-$688	$5,452
2011	$381	-$2,428	-$602	-$2,649
2012	$2,574	-$2,394	$488	$668
Total	**$3,176**	**-$727**	**-$1,873**	**$576**

4.2 Addressing Required Evaluation Questions Related to Program Mechanics

Several of the required evaluation questions require an assessment of program mechanics. In this sub-section, we will address each one using the insights gathered from our investigation of the Schedule 123 mechanics. Note that many evaluation questions are answered in other sections of the report. The question numbering corresponds to that used in Section 3.

1. Did the mechanisms effectively remove the relationship between the utility's sales and profits?

No, Schedule 123 was not designed to completely remove the relationship between sales and profits. First, the schedule is not applicable to customers over 1 aMW, so changes in sales to these larger customers will continue to affect PGE's profit in the same manner that it would in the absence of Schedule 123.

Second, the LRRA applied to larger C&I (and some other) customers only adjusts utility revenues for changes in usage that can be attributed to ETO-sponsored conservation programs. The revenue effects of all other changes in sales to these customers are unchanged by Schedule 123.

Third, even for the SNA-eligible customers, the SNA does not affect the relationship between weather-induced fluctuations in sales and PGE revenue. Because this is a significant source of variability in sales to these customers, PGE's profits continue to be affected by variations in sales.

2. Did the mechanism effectively mitigate the utility's disincentive to promote energy efficiency?
Yes, for Schedules 7 and 32. The SNA appears to eliminate, at least the short-term, utility disincentives to promote conservation and energy efficiency.[9] The utility does not control weather conditions, so the fact that such variability is retained under the SNA does not affect PGE's incentives with respect to conservation.

For customers on the LRRA, the utility continues to have a disincentive to promote any conservation that it does not believe will be captured in ETO's estimates of program-induced conservation. In addition, under the LRRA the utility retains an incentive to *increase* customer sales. In contrast, under the SNA, PGE does not benefit from increases in use per customer.

3. Did the mechanisms improve the utility's ability to recover its fixed costs?
The answers to this question are specific to each mechanism. The LRRA is comparatively limited in scope: prevent/mitigate utility revenue attrition due to the ETO's conservation programs. The effectiveness of the LRRA in eliminating these losses is directly related to the accuracy of the ETO's estimates of conservation savings. If the estimated savings are accurate, PGE will continue to recover the fixed costs associated with the lost sales. PGE's recovery of fixed costs in the presence of other sales changes under the applicable rate schedules is unaffected by the LRRA.

For the SNA, the answer is considerably more complicated, and highly specific to condition. Under standard rates, the amount of net revenue collected by PGE to cover fixed costs is directly related to how much energy its customers (on Schedules 7 and 32) use. When current customers conserve or use less energy relative to test year levels, PGE recovers less revenue available to cover fixed costs. Conversely, when current customers use more energy, PGE recovers more revenue contribution toward fixed costs, when compared to test year levels. When a new customer joins the system, PGE gains revenue in approximate proportion to the customer's usage, recognizing that net impacts are highly specific to both load shape and the rate schedule under which new customers take service.

The SNA alters these outcomes. The SNA replaces the link between revenue and sales with a link between revenue and the number of customers served. This leads to two different types of effects: those attributable to changes in the number of customers served; and those resulting from changes in energy usage of existing customers.

In the former category (change in customers served), the SNA only alters PGE's revenue to cover fixed costs to the extent that the added or lost customers are different in size from the average of current customers served (based on the test-year forecast of sales). That is, when average-sized customers join (or leave) PGE's system, the revenue effects of standard rates and

[9] The utility's longer-term incentive to grow load to "put more steel in the ground" and thus have a higher rate base upon which to earn a rate of return is not addressed by Schedule 123. However, with ETO goals of approximately 1% incremental conservation per year, this longer-term incentive may not be relevant for PGE.

the SNA are the same (i.e., because there is no SNA deferral when use per customer does not change). If a larger-than-average customer joins the system, PGE collects *less* revenue under the SNA than it would under standard rates. Conversely, if a smaller-than-average customer joins the system, PGE collects *more* revenue under the SNA than it would under standard rates. Whether the adoption of the SNA improves PGE's ability to recover fixed costs in this situation therefore depends on: the size of the customer; whether PGE's estimates of the marginal cost to serve a customer is accurate and closely related to the size of the customer.[10] We explore the relationship of the SNA to PGE's marginal costs more in Section 4.3.

The second type of change to consider under the SNA is the effect of changes in usage by current customers. In this second case, the differences between the SNA and standard rates are more significant. Increases in sales above test-year levels lead to a higher share of recovery of fixed costs under standard rates, but not under the SNA.[11] Conversely, conservation (or reduced energy usage) on the part of current customers leads to lower coverage of fixed costs under standard rates, but not under the SNA. Thus, it appears that the SNA improves PGE's ability to recover its fixed costs, with the caveat that it does not address fixed-cost recovery issues that arise because of deviations from normal weather conditions (e.g., customers using more energy in a hot summer).

7. PGE's mechanism is based on a volumetric fixed charge. However, the amount of revenue available for fixed cost recovery may vary depending on the variable cost of the power being sold or purchased. (Revenue/kWh minus variable power cost/kWh equals revenue available for fixed costs.) Should the volumetric fixed charge decoupling rates be calculated in a different manner in order to account for this? For example, as the difference between total volumetric rates for both Schedules 7 and 32 and a measurement of short-run marginal energy costs such as the Mid-Columbia Index?

No, we believe that the current method is effective. The fixed generation component of the SNA is calculated by subtracting net variable power costs from total production costs (where both represent test-year forecasts). This results in a reasonable estimate of the total fixed generation costs, which are subsequently allocated to rate schedules and unitized using the forecast number of customers and sales. This estimate does not change with variable power costs. That is, if one were to recalculate the fixed generation costs under the assumption of higher market prices, both total production costs and net variable power costs would increase, leaving the difference (fixed generation costs) unchanged.

[10] We do not favor excluding or separately tracking new customers under decoupling mechanisms. Excluding new customers from the decoupling mechanism removes the utility's incentive to ensure that new customers are as energy efficient as possible. Separately tracking new customer adds to the complexity and administrative costs of the mechanism, and still requires a forecast of the average size of new customers. Differences between the forecast and the average size of the customers actually added will continue to exist.

[11] Note that if actual fixed costs are equal to regulatory-allowed fixed costs within the test year, revenues over-recover regulatory costs, other factors constant.

However, it may be the case that the SNA produces fixed generation cost recovery that differs from what would have occurred in its absence. Whether the effect of the SNA is to increase or decrease PGE's fixed generation cost recovery, when compared to test year allowed cost levels, depends on a variety of factors, including:

- Whether variable power costs (e.g., wholesale market energy prices) are higher or lower than forecast values;
- Whether changes in sales are due to a change in the number of customer served or a change in the usage of existing customers;
- Whether the number of customers is increasing or decreasing; and
- Whether use per customer is increasing or decreasing.[12]

We do not find reason that PGE's SNA mechanism introduces bias in fixed cost generation revenues because of the use of a fixed per-customer and per-kWh fixed cost generation component. A separate, but related question regarding whether the generation and transmission components of the SNA should be treated differently than the distribution component is addressed in Section 4.3.

4.3 The Relationship between SNA Revenues and Marginal Costs

The SNA allows PGE's revenue toward fixed costs to increase as it serves more customers. The sixth evaluation requirement (listed in Section 3) concerns the relationship between the SNA's allowed revenue per customer and the marginal cost of serving additional customers. Here is the requirement:

6. To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in UE 197 and in any subsequent general rate case?

Many factors could lead to an increase in fixed costs over time, including changes in the utility's cost function (e.g., increases in costs associated with planned distribution system maintenance) or the addition of customers to the system. The SNA is designed as though fixed costs are directly related to the number of customers served. The analysis requirement listed above appears to ask about the extent to which fixed costs have evolved in a manner consistent with the design of the SNA.

Two pieces of evidence are available to assist in answering this question. First, we can see how the Monthly Fixed Charge per Customer has evolved since the introduction of the SNA. Table 4.3.1 contains the SNA Monthly Fixed Charges per Customer, by Schedule and rate case (i.e., time period). When the SNA was introduced, the allowed revenue per customer month was $41.38 for residential customers and $63.47 for small commercial customers. By the subsequent rate case (UE-215), PGE had added customers in both of these rate classes. In addition, the SNA charges increased for both groups, to $49.94 and $75.81 respectively. These

[12] Note that if use per customer doesn't change relative to test-year levels, the SNA doesn't produce a deferral regardless of the number of customers served. In this case, the SNA can't alter the amount of generation fixed cost revenue that PGE collects.

are direct indications that the fixed costs covered by the SNA increased over time. PGE's current filing (UG-262) proposes a further increase in those charges, which is also associated with an increase in the number of customers served. The relatively small increases in the number of customers served relative to the increases in the SNA Monthly Fixed Charges makes it highly unlikely that customer growth was a significant driver of the increased per-customer charges (e.g., compared to the costs associated with modernizing existing infrastructure). However, the values in Table 4.3.1 do indicate that the per-customer "fixed" costs vary over time, and have tended to increase in recent years.

Table 4.3.1: SNA Parameters across Rate Cases

Docket and Timeframe	Number of Customers		SNA Monthly Fixed Charge per Customer	
	Schedule 7	Schedule 32	Schedule 7	Schedule 32
UE-197 (2009-2010)	715,517	84,620	$41.38	$63.47
UE-215 (2011-current)	721,537	86,153	$49.94	$75.81
UE-262 (as filed)	734,050	88,797	$56.77	$95.05

Table 4.3.2 presents a comparison of the SNA fixed charges and the marginal costs associated with serving an additional customer, using information from PGE's marginal cost of service study from UE-215. While this table does not reveal the incremental costs associated with the new customers added between rate cases, it does provide estimates of the costs of adding customers, using methods applied by PGE for cost allocation purposes.

In the parlance of PGE's marginal cost study, costs are estimated for three functions of integrated electricity services[13] customer-related costs (e.g., transformation, metering, billing), distribution (transport services); and generation (power supply). Customer-related costs are expressed in dollars per customer month and, for the immediate purposes, require no adjustment. Distribution costs are presumed to be exclusively driven by peak loads, and are thus expressed in $/kW-year. Using class-level sales data and an assumption of a 60 percent load factor, we estimated demand of approximately 2kW per customer for Schedule 7 and 3.3kW for Schedule 32. Generation capacity costs are estimated by PGE to be $191.18 per kW-year which, in turn, is multiplied by the estimates of demand (2kW, 3.3kW). This result is combined with the customer and distribution costs to obtain estimates of marginal costs per customer covering customer (i.e., incremental interconnection services) and demand-related costs. Note that marginal energy costs including energy and line losses are not covered.

In Table 4.3.2, PGE's marginal cost estimates are compared to the annual revenue per customer allowed under the SNA (12 x the SNA Monthly Fixed Charge per Customer). For each of the three schedules/customer groups, the marginal cost to serve is higher than the revenue allowed under the SNA. A significant portion of the non-fuel marginal cost to serve an additional customer is associated with generation capacity. For a defined timeframe, such level

[13] Transmission and ancillary services are omitted because they are of comparatively small magnitude with respect to customer-, distribution-, and generation capacity-related cost categories.

of generation capacity cost may not necessarily be *on the margin*, and thus actually reflected in PGE's financial costs, as it serves an additional customer. We anticipate that, within an annual timeframe, customer- and load-related distribution costs are perhaps more representative of PGE's actual experience *on average*, recognizing the wide variation in the underlying costs across individual customers served. That is, within an annual period, if PGE serves additional load through wholesale market purchases (or a reduction in wholesale market sales), the value of these transactions is accounted for in its power cost adjustment schedules. Under such condition, PGE is exposed to cost recovery shortfalls (or may be long) to the extent that: a) the costs are not accounted for in the Schedule 125 forecast; and/or b) the Schedule 126 variance mechanism does not fully compensate PGE for the cost variance relative to the forecast.

Table 4.3.2: Comparison of SNA Revenue per Customer and Marginal Costs using UE-215 Rates

Category	Schedule 7	Schedule 32, Single Phase	Schedule 32, Three Phase
Customer-related	$154	$194	$380
Distribution	$123	$235	$191
Generation Capacity	$383	$625	$625
Marginal Cost (non-fuel)	**$660**	**$1,054**	**$1,196**
SNA Fixed Charge per Customer Year	**$599**	**$910**	**$910**

There are two additional questions that relate to PGE's marginal costs, which are addressed below.

8. What is the effect of a change in load (as included in this mechanism) on PGE's costs? What is the effect of the change in load on revenue? Has this mechanism accurately accounted for these changes? On a going-forward basis is this mechanism likely to accurately account for these changes?

In the absence of the SNA, the retail rates define the effect of a change in sales on PGE's revenue. Schedule 126 (the true-up schedule) could alter revenues in the longer term if wholesale costs to serve are higher or lower than expected. With the SNA, the utility's revenue stream depends on the source of the increased sales. In the case of sales (and therefore revenue) increases from current customers, PGE retains the portion that covers variable energy costs but refunds the portion for coverage of non-variable costs (assuming that the load level is above test-year sales estimates). In the case of new customers, PGE realizes an increase in revenue, as though a typical (average-sized) customer joins the system.

Regarding the effect of a change in load on PGE's cost, we again refer to PGE's marginal cost of service study. Therein, estimates of marginal customer- and capacity-costs imply that PGE loses money (increases earnings) as the number of customers increases (decreases). Implicitly, then, marginal costs are above the average cost of service). However, the *true* incremental costs associated with increased/decreased energy sales or customers are highly specific to context, and can vary dramatically depending on the circumstances—e.g., whether the load change during a peak hour or an off-peak hour, the specific location of the customer within PGE's distribution system, the customer's size and load factor, or wholesale market conditions, or whether PGE is comparatively short or long in capacity (evidence clearly suggests that PGE is capacity short, currently).

Note: standard rates do not necessarily do a good job of associating changes in revenues and the true changes in costs. The relevant question is whether the SNA tracks the true underlying costs on the margin vis-à-vis standard rates. As the discussion proceeds, we will demonstrate that the SNA does not appear to perform worse than standard rates across all possible outcomes, but the particular outcome is specific to conditions (e.g., cost conditions, sales levels, etc.).

11. Should the mechanism be bifurcated such that the total kWh for each of Schedules 7 and 32 are fixed for and beyond the test period for purposes of recovery/refund of transmission and generation fixed revenue requirements? Calculation of the fixed revenue requirements for functions other than generation and transmission would be in the same manner as is currently done.

The question suggests an alternative SNA design in which the allowed revenue level (rather than revenue per customer) for the generation and transmission components of the SNA is fixed. In the current SNA formulation, the allowed revenue changes when the number of customers served changes. Under standard rates, however, revenues change with changes in sales level, as volumetric charges (i.e., $/kWh) are the basis to recover fixed generation costs.

It is useful to illustrate the impacts of these methods on utility revenues through a highly stylized example. Suppose rates are set using projections of 100 customers, each using 1,000 kWh during the test year. For the test year, normalized fixed generation costs are $2,500, or $0.025 per kWh (and $25.00 per customer). Tables 4.3.3a and 4.3.3b below illustrate how fixed generation costs are recovered as use-per-customer (UPC) and the number of customers served deviates from test-year levels, other factors constant.

The columns in the table present alternative levels of use per customer ("UPC"), including 5% changes (decreases and increases of 50 kWh) from the test-year level of 1,000 kWh per customer—i.e., alternative sales scenarios of 950 and 1,050 kWh, respectively. The rows contain three scenarios of the number of customers served, including the test-year level (100) and alternative scenarios of 95 and 105 customers.

Three results panels are presented in Table 4.3.3a, including *Sales*, which shows the total sales for each of the nine scenarios examined.[14] The middle panel, labeled "Revenue, Standard Rates", shows the realized revenue (for fixed generation costs) obtained under each scenario,

[14] Sales are calculated as the product of the number of customers and use per customer.

presuming that costs are recovered with volumetric charges—for each scenario, revenue is the product of sales and $0.025/kWh.

The bottom panel, labeled "Revenue with Decoupling", shows the realized revenue for fixed generation costs under the implementation of a revenue-per-customer decoupling mechanism. The calculation of the adjustment from the "Standard Rates" panel, to obtain the results shown in this third panel is as follows:

Decoupling Adjustment = # of customers x $0.025/kWh x (1,000 kWh – Scenario UPC)

Table 4.3.3a: Example Illustrating Scenarios of Fixed Generation Cost Recovery

Outcome	Number of Customers	Use Per Customer		
		1,000 kWh	950 kWh	1,050 kWh
Sales	100	100,000	95,000	105,000
	95	95,000	90,250	99,750
	105	105,000	99,750	110,250
Revenue, Standard Rates	100	$2,500	$2,375	$2,625
	95	$2,375	$2,256	$2,494
	105	$2,625	$2,494	$2,756
Revenue with Decoupling	100	$2,500	$2,500	$2,500
	95	$2,375	$2,375	$2,375
	105	$2,625	$2,625	$2,625

Shown below in Table 4.3.3b are the differences between the realized revenue for coverage of fixed generation costs, under each scenario, and the $2,500 in fixed generation costs set during the rate case proceeding. In the top panel, *Revenue Under Standard Rates*, the utility recovers the allowed revenue only when the number of customers and UPC are at test-year levels. When sales exceed test-year levels, utility recovers greater revenue (e.g., by $256 under the higher scenarios for both number of customers (105) and UPC (1,050)); realized revenues are below test year fixed generation costs when sales are below test-year levels, which occurs in 5 of the 9 nine scenarios.

Table 4.3.3b: Example Illustrating Scenarios of Fixed Generation Cost Recovery

Difference from Test-year Fixed Generation Costs	Number of Customers	Use Per Customer		
		1,000 kWh	950 kWh	1,050 kWh
Revenue Under Standard Rates	100	$0	-$125	$125
	95	-$125	-$244	-$6
	105	$125	-$6	$256
Revenue with Decoupling	100	$0	$0	$0
	95	-$125	-$125	-$125
	105	$125	$125	$125

Scenario results differ under decoupling, where the amount of revenue for recovery of fixed generation costs depends entirely on the number of customers served (e.g., the utility under-recovers by $125 when it serves 95 customers, regardless of the level of UPC).

One scenario is of particular interest: *increased number of customers and decreased sales.*[15] Here, standard rates obtain a modest under-recovery of fixed generation costs (-$6), while the decoupling mechanism results in *increased* revenue for fixed generation costs (+$125) despite the fact that less total load is served.

In summary, under standard rates, in which fixed costs are recovered with volumetric rates, the utility over- or under-recovers test year fixed generation costs in proportion to changes in *sales*. Under revenue-per-customer decoupling, the utility over- or under-recovers such costs in proportion to changes in *the number of customers*. Neither approach guarantees that test year (fixed generation) costs are matched by revenues. Among the four scenarios in which UPC and the number of customers deviate from test-year values, decoupling improves the test year cost-revenue match vis-à-vis standard rates under 4 of the 8 alternative scenarios (where “improves” is defined as a reduced difference between collected revenues and test-year costs, when compared to standard rates). Accordingly, it does not appear that decoupling performs worse than standard rates.[16]

Yet, a bifurcation of the decoupling mechanism such that allowed fixed generation revenue remains constant regardless of the number of customers served or the level of UPC ensures, in our example, that the service provider realizes revenues equivalent to allowed fixed generation costs. This appears to improve on the scenario outcomes obtained under both standard rates and decoupling, notwithstanding incentive associated with a lock-in revenue-test year cost approach.

[15] Number of customers rises to 105 but total sales declines to 99,750 kWh.

[16] One could argue that decoupling may be expected to perform worse than standard rates if it is most likely that a) the number of customers will increase; and b) UPC will decrease due to successful conservation. Based on historical trends, the former seems very likely but there is mixed evidence on the latter. (E.g., reductions in UPC due to successful conservation programs may be offset by increased prevalence of energy-intensive end uses.)

Note that the above discussion compares realized revenues and test-year fixed costs. In this case, “fixed cost” refers to the absence of a relationship between the level of total costs and short-term fluctuations in sales. However, the fixed-cost basis of rates is financial costs, either observed or estimated for defined timeframes, such as historical or projected test years. Financial costs and changes in fixed costs through time (e.g., between general rate proceedings) often change significantly. Including foreseeable events as well as unanticipated contingencies, the list is long: accounting measures of the worth of facilities decline as a result of capital depletion; physical capital is replaced, where incremental costs are several fold that of net plant value; storm activity that imposes major service dislocations on consumers and foregone revenues on utilities; generator unit outages caused by equipment failures; and distribution service failures precipitated by unanticipated high loads; and environmental compliance costs. None is associated with output quantities, either changes in energy sales or the number of customers served. If such events are inherently “inflationary” to electricity tariff prices, bifurcation of decoupling would reduce the utility’s ability to recover its fixed generation costs. If the number of customers served increases at a relatively modest rate (of perhaps 1 percent per year), the decoupling mechanism is compatible with inherent inflationary pressures.

However, there is an alternative that is likely to be superior to either of these options (continuing the current methodology or fixing allowed generation and transmission revenue). It begins by bifurcating fixed generation and transmission costs, but instead of fixing the amount of allowed revenue, it is set at an index of industry-wide input cost measures. This prevents the utility from being harmed by exogenous increases in costs, prevents them from benefitting from exogenous decreases in costs, and provides it with an incentive to outperform the industry average (i.e., it is not a cost tracker – the utility benefits or suffers from deviations from industry-average costs). In this way, an incentive regulation component is integrated into the decoupling mechanism, the details of which would require additional exploration.

In conclusion, there is good cause for the separation of generation and transmission (G&T) from distribution under PGE’s SNA decoupling mechanism, as the underlying G&T costs are more closely related to sales volumes than the number of customers served, other factors held constant. Nonetheless, PGE’s current approach to decoupling does not appear to function worse than standard rates, at least under the initial review conducted herein. In addition, locking in revenues to match test-year costs for G&T could be punitive if the G&T functions are facing rising cost pressures. Finally, bifurcation may be a preferred approach and obtain improved results if the amount of revenue is tied to an industry cost index. Specific results, however, are highly conditional to market context and cost pressures facing the G&T functions; further analysis is necessary in order to explore more fully how such approach might be best constructed.

4.4 Statistical Analysis of Use per Customer

The SNA adjusts utility revenues for the effects of deviations of sales per customer from forecast levels (used when base rates are set) due to any cause except weather.[17] For the most part, this characteristic reduces risk for both the utility and its ratepayers, where we define "risk" as the variability of revenue (or bills) toward fixed costs over time. That is, by preventing utility over- and under-recovery of fixed costs, the mechanism also prevents ratepayer over- and under-payment of fixed costs.[18]

However, there are two cases in which the SNA may shift risk from the utility to its ratepayers: *economic* risk and *rate* risk. For example, if an economic recession causes customers to reduce their usage in an attempt to save money, the fixed-cost portion of the resulting bill reduction will be paid to the utility in the following year through an SNA-induced rate increase.[19] Thus, the SNA could make a bad situation worse for ratepayers even as it would mitigate the adverse effects of the recession for PGE. A similar argument can be made regarding a customer who conserves in the face of rising energy costs.[20]

A conserving customer does not directly pay back the fixed-cost portion of its bill reduction. Rather, those costs are spread across all customers in its rate class through an SNA-induced rate increase in the following year. The SNA only affects rates and revenues through changes in class-level use per customer. Therefore, in order to determine whether the SNA shifts economic risk from PGE to its customers, we examine the effect of economic conditions on class-level use per customer. The economic risk is only shifted from PGE to its customers if there is a statistically significant relationship between the two factors (i.e., if UPC declines during recessions). Similarly, rate risk can only be shifted from PGE to its customers if there is a statistically significant relationship retail volumetric rates and class-level UPC.[21]

Figures 4.4.1 and 4.4.2 illustrate the potential difficulty in identifying an effect of economic conditions on use per customer that is distinct from an SNA effect. Figure 4.4.1 shows UPC

[17] Recall that the mechanism attempts to remove the effects of weather by adjusting sales so that they represent sales at normal weather conditions.

[18] Note that this discussion does not apply to the LRRA, which only affects revenues and bills when forecast conservation differs from observed (estimated) conservation.

[19] In more formal economic terms, the recession reduces customer income, which (if electricity is a normal good) causes customers to reduce their electricity use. The resulting reduction in sales leads to a positive SNA deferral, increasing rates in the following year and further reducing customer welfare.

[20] It should be noted that in all cases, customer conservation leads to a reduction in total customer bills (all else equal) even after accounting for the effect of the SNA deferral, as variable energy costs are not included in the SNA.

[21] Weather is another source of revenue and bill risk, but the SNA excludes the effect of weather on sales from its deferrals. In comments, Staff indicated the possibility of other sources of risk shifting: efficiency gains, changes in population, and technological innovations. We do not consider these sources in this study due to data limitations (e.g., we do not have information on appliance efficiency levels and saturation rates). However, we do not expect these sources of risk to be as volatile in the near term as the sources we do consider. For example, we expect economic conditions and electricity commodity prices to change much more rapidly than average electric intensity (reflecting efficiency gains and technological innovations) or population levels.

values for customers on Schedules 7 and 32. Figure 4.4.2 shows the Oregon unemployment rate and gross domestic product (GDP). In both figures, the vertical line indicates the date on which the SNA became effective. As Figure 4.4.2 shows, the SNA was implemented in the midst of a worsening of economic conditions. The coincidence of these two events (the recession and the implementation of the SNA) may make it difficult for the statistical model to separate the effect of each on UPC.

Figure 4.4.1: Use per Customer for Schedules 7 and 32

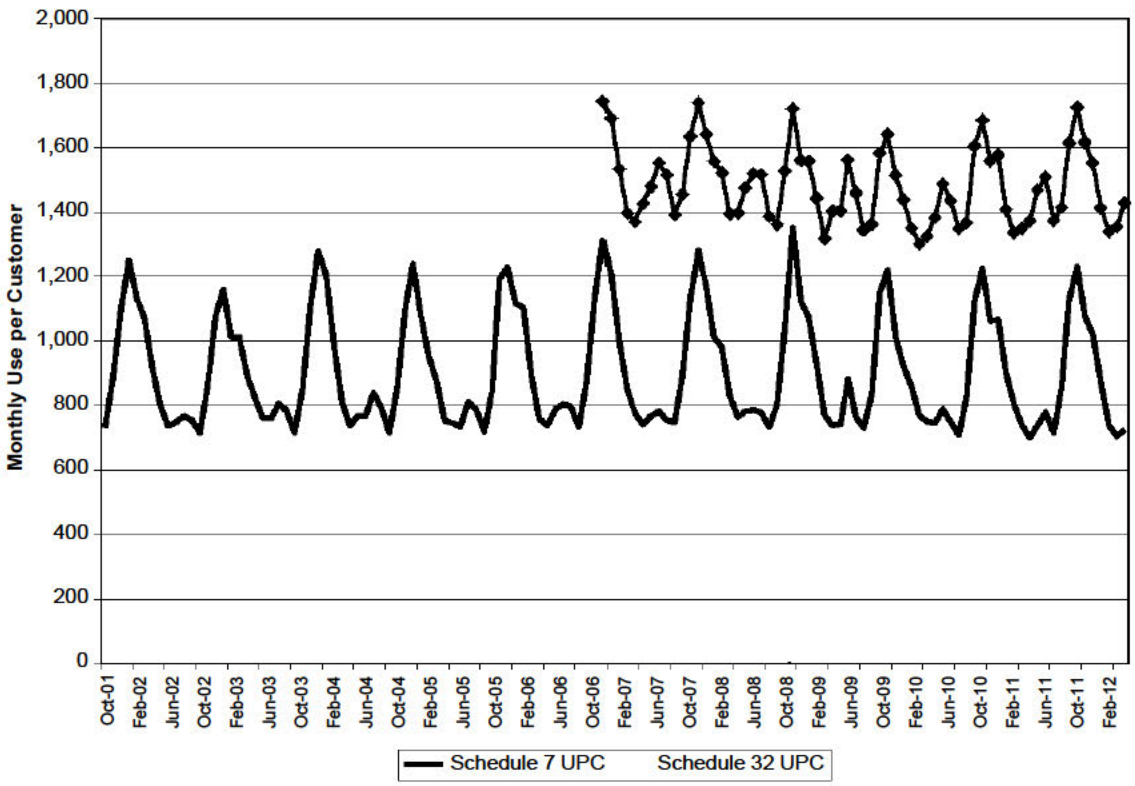

Figure 4.4.2: Oregon Unemployment Rate and Real Gross Domestic Product

The statistical model is shown in Equation 4.

Equation 4:

$$UPC_{c,t} = a + b_{CDD} \times CDD_t + b_{HDD} \times HDD_t + b_{Econ} \times Econ_t + b_{Trend} \times Trend_t + b_{Rate} \times Rate_{c,t}$$
$$+ \sum_{i=2}^{12} b_i \times Month_{i,t} + e_t$$

Table 4.4.1: Variables Included in the Statistical Models

Variable Name / Term	Description
$UPC_{c,t}$	Use per customer for customer group *c* in month *t*
a and the various *b*'s	The estimated parameters
CDD_t	Cooling degree days in month *t*
HDD_t	Heating degree days in month *t*
$Econ_t$	Economic conditions in month *t*
$Trend_t$	Time trend variable
$Rate_{c,t}$	The average retail rate for customer group *c* in month *t*
$Month_{i,t}$	An indicator variable for month *i* at time *t*
e_t	The error term

Separate models are estimated for each rate schedule (7 and 32).[22] The dependent variable is UPC for the rate schedule in question. Weather conditions are accounted for through the CDD and HDD variables.[23] The economic variable is either the Oregon unemployment rate or the natural log of real GDP. The time trend variable increments 1/12 each month, such that the estimated coefficient on the variable is interpreted as the annual change in UPC, controlling for other included factors. The rate variable is constructed as the average retail rate calculated from the rates for each usage block (converted to 2005 dollars using the Consumer Price Index), the block sizes and UPC for the customer class and month in question. The month indicator variables account for seasonal patterns in UPC not captured by the weather variables.[24] In some models, we include an SNA indicator variable that equals 0 prior to February 2009 and 1 after. This variable is intended to capture any changes in UPC that occurred because the SNA was in place.

Five alternative model specifications were estimated for each rate schedule. The first includes only weather and monthly indicator variables. These results are intended to demonstrate that a very large portion of fluctuations in UPC can be explained by only weather and seasonal patterns. The four additional specifications all contain the time trend variable, the average retail rate, and one measure of economic conditions (either real GDP or the Oregon unemployment rate). Finally, we estimate specifications with and without the SNA indicator variable. Because the SNA was introduced in the midst of a recession, it may be useful to examine the relationship between UPC and economic conditions with and without the SNA variable.

For each specification, we report the number of observations (N) and the R-squared value, which is the proportion of the variation in UPC that is explained by the included variables.[25] Asterisks are included to indicate the level of statistical significance of the estimated effect of the variable in question.[26] The absence of an asterisk means that the coefficient is not statistically significantly different from zero (i.e., the estimates indicate that the variable has no effect on UPC).

Table 4.4.2 contains the estimates for the Schedule 7 models.[27] The R-squared value for the first model (0.976) shows that over 97 percent of the variation in UPC can be explained by just the

[22] Prais-Winsten estimation is conducted to account for serial correlation, which is the tendency for the regression error in a given time period to be related to the error in the previous time period.

[23] $CDD_m = \Sigma_d \max\{0, (MaxTemp_d + MinTemp_d) / 2 - 65\}$. $HDD_m = \Sigma_d \max\{0, 65 - (MaxTemp_d + MinTemp_d) / 2\}$. In both equations, *m* refers to the month in question and *d* indexes the days of that month.

[24] In all of the models we estimate, the monthly indicator variables are jointly statistically significant. That is, they capture variation in UPC that the other included variables do not.

[25] R-squared ranges from 0 to 1, where 0 indicates that the variables do not explain any variation in UPC and 1 indicates that the variables explain all of the variation in UPC.

[26] Three asterisks indicate a p-value less than 0.01; two asterisks indicate a p-value less than 0.05; and one asterisk indicates a p-value less than 0.10.

[27] While the monthly indicator variables are included in all models, we do not report their estimated coefficients for compactness.

weather and monthly indicator variables. The second column of results contains the following results of interest:

- A statistically significant time trend, indicating an 8.9 kWh per year reduction in UPC;
- A statistically significant effect of real GDP on UPC, with a 1 percent increase in real GDP corresponding to a 3.47 kWh increase in UPC; and
- No relationship between the average retail rate and UPC.

The third column of results replaces the GDP variable with the Oregon unemployment rate (where, for example, 8 percent is represented as 8.0). This change does not affect the CDD and HDD variables (which are doing most of the work in explaining changes in UPC), but it does reduce the magnitude of the time trend effect from -8.9 to -2.5. The unemployment rate is statistically significant, but only at the 90 percent level (whereas the GDP variable was significant at the 99 percent level). The size of the effect indicates that a 1 percent increase in the unemployment rate reduces UPC by 3.1 kWh.

Columns 4 and 5 show how the results are affected by introducing an indicator for the dates during which the SNA was in effect. Once again, the coefficients on the weather variables are not affected. However, the introduction of the SNA variable causes the estimates on the economic and time trend variables to lose their statistical significance. The SNA indicator itself is statistically significant in the Oregon unemployment model (column 5), indicating that UPC was 38.2 kWh lower when the SNA was in effect, all else equal. This is approximately 4 percent of the average UPC across all months.[28]

[28] In comments, Staff requested that we include an interaction between the economic variable and he SNA dummy variable to see whether the SNA makes customers more or less responsive to economic shocks. Specifically Staff stated that “the analysis identifies that customers are less responsive to economic variables in the presence of the SNA. The findings could be driven by the correlation between the dummy variable and the economic variables. Alternately, the results could be driven by a structural break caused by the introduction of the SNA.” We conducted this test for the models shown in the fourth and fifth columns of Tables 4.4.2 and 4.4.3. There is only one model (the GDP model for Schedule 7 customers) in which the interaction variable is statistically significantly different from zero (at the 90 percent level). However, the other coefficients do not appear to be altered reasonable ways. Specifically, the results imply no statistically significant effect of economic conditions on UPC before or after implementation of the SNA; and a statistically significant *increase* in UPC after introducing the SNA (all else equal). In summary, we believe that Staff’s theory that the results in Tables 4.4.2 and 4.4.3 reflect “correlation between the dummy variable and the economic variables” is much more plausible than the theory that the “SNA makes customers more or less responsive to economic shocks.”

Table 4.4.2: Statistical Model Results, *Schedule 7*

Variable	Weather & Month Only (1)	GDP, No SNA (2)	OR Unempl, No SNA (3)	GDP, SNA (4)	OR Unempl, SNA (5)
CDD	0.76***	0.76***	0.76***	0.76***	0.74***
HDD	0.68***	0.70***	0.70***	0.70***	0.70***
Trend		-8.9***	-2.5**	-5.6	0.3
ln(Real GDP)		347***		221	
OR Unempl.			-3.1*		1.7
Avg. Rate		4.59	-0.07	5.05	3.27
SNA				-13.1	-38.2**
Constant	726***	-2,549**	749***	-1,382	683***
N	130	130	130	130	130
R-squared	0.976	0.984	0.983	0.984	0.982

Table 4.4.3 shows the results for Schedule 32 customers. There are some similarities to the residential results, namely:

- Weather and seasonal factors explain a very high proportion of the variation in UPC;
- There is no statistically significant relationship between UPC and retail rates; and
- There is some evidence of a downward trend in UPC, but the finding is not robust across specifications.

The key differences between the Schedule 7 and 32 results are:

- The relationship between UPC and economic conditions is more robust for Schedule 32. The coefficient on the economic variable is statistically significant in each of the Schedule 32 models.
- There no statistically significant relationship between Schedule 32 UPC and the SNA indicator variable. That is, we do not find lower UPC during the dates in which the SNA was in effect, all else equal.

Table 4.4.3: Statistical Model Results, *Schedule 32*

Variable	Weather & Month Only (1)	GDP, No SNA (2)	OR Unempl, No SNA (3)	GDP, SNA (4)	OR Unempl, SNA (5)
CDD	0.84***	0.91***	0.89***	0.91***	0.89***
HDD	0.44***	0.42***	0.41***	0.42***	0.41***
Trend		-17.6***	-0.8	-12.6*	-0.3
ln(Real GDP)		1,246***		1,030***	
OR Unempl.			-12.8***		-12.1***
Avg. Rate		21.43	23.70	33.78	26.25
SNA				-23.8	-5.9
Constant	1,354***	-10,486***	1,289***	-8,564***	1,260***
N	67	67	67	67	67
R-squared	0.969	0.972	0.972	0.973	0.972

Overall, the statistical models show:

- A relationship between UPC and economic conditions, indicating that the SNA shifts some economic risk from PGE to its ratepayers;

- No relationship between UPC and retail prices, indicating that the SNA **does not** shift rate risk from PGE to its ratepayers.
- Limited evidence that the SNA has affected UPC, with a statistically significant estimate showing up in only one of the residential (Schedule 7) models.

The limited effect of SNA on UPC is perhaps not surprising, as conservation effects may be expected to be somewhat small initially and build over time. The SNA indicator variable estimates an overall conservation effect during SNA, beginning the month after its introduction.[29]

While the estimates indicate that the SNA shifts economic risk from PGE to its customers, it may help to provide some context for the magnitude of the changes in UPC that occur as economic conditions change. Table 4.4.4 is an attempt to provide that context. It shows the percentage change in UPC[30] that occur under two scenarios of changes in economic conditions:

- "Since SNA Implementation" represents the simulated effects on UPC using the changes in economic conditions that have occurred since the introduction of the SNA, which are a 1.1 percentage point decrease in the Oregon unemployment rate and a 0.06% increase in real GDP.
- "Peak to Trough" is a sort of worst-case scenario, representing the change in economic conditions that occurred during the most recent recession: a 5 percentage point increase in the Oregon unemployment rate and a 5 percent decrease in real GDP.

Table 4.4.4: Simulated Effects of Changes in Economic Conditions on UPC

SNA Variable Included?	Economic Variable	Since SNA Implementation		Peak to Trough Scenario	
		Schedule 7	Schedule 32	Schedule 7	Schedule 32
No	Real GDP	2.3%	5.0%	-1.9%	-4.2%
	OR Unemployment	0.4%	1.0%	-1.7%	-4.3%
Yes	Real GDP	n/a	4.2%	n/a	-3.5%
	OR Unemployment	n/a	0.9%	n/a	-4.1%
	Average	**1.3%**	**2.8%**	**-1.8%**	**-4.0%**

The results in Table 4.4.4 show that a shift in economic risk from PGE to its ratepayers does not necessarily result in a negative outcome for the ratepayers. Because economic conditions have improved since the introduction of the SNA, we estimate that they have caused UPC to increase, contributing to SNA-induced rate decreases for customers. The magnitude of the increase in UPC is 0 percent (i.e., no statistically significant effect, shown as "n/a") to 2.3

[29] We estimated alternative models that allowed the time trend in UPC to change after the introduction of the SNA (rather than changes in the overall level of UPC, as the SNA indicator variable estimates). The pattern of the results does not change. The only statistically significant effect of the SNA on the time trend in UPC occurs in the same model in which we estimate a statistically significant effect of the SNA on the level of UPC (the Schedule 7 model with the Oregon unemployment rate).

[30] Percentage changes are calculated using the average UPC across the sample period in the denominator. These values are 903 kWh for Schedule 7 and 1,481 kWh for Schedule 32.

percent for Schedule 7 customers and 0.9 to 5.0 percent for Schedule 32 customers. Note that the percentage changes in UPC overstate the percentage change in the overall retail rate since the SNA only covers revenues toward fixed costs.

The “Peak to Trough” scenario provides an idea of the size of SNA effects as a result of a somewhat severe recession. The resulting reductions in UPC for both customers on rate schedules lead to SNA-induced rate increases in the following year. For Schedule 7 customers, UPC decreases by 0 to 1.9 percent; while for Schedule 32 customers, the decrease ranges from 3.5 to 4.3 percent. Note that the SNA-induced rate increases are capped at 2 percent of total revenues (including variable costs not covered by the SNA) with no ability for the utility to recover the excess in future time periods. The simulated decrease in UPC for Schedule 32 may be large enough to reach this cap. (Recall that there is no cap on the rate reduction that SNA produces.)

It is interesting to note that, despite the statistical evidence that the SNA shifts economic risk from PGE to its ratepayers, Standard & Poor’s credit analyses continued to note the adverse effects of the recession on PGE’s finances, as reflected in this excerpt from S&P’s February 2010 analyses.

> The 'BBB' corporate credit rating and stable outlook on Portland General Electric Co. (PGE) reflect Standard & Poor's Ratings Services' opinion that the company's financial risk profile is under strain due to a recessionary environment that is particularly severe in Oregon; falling electric sales that have reduced cash flows in 2009, despite a recently approved decoupling mechanism that covers only residential customers; a high level of capital investment, of which a large portion is not discretionary; and collateral requirements tied to the company's hedging strategy for its sizable power purchases.

Therefore, while it appears that the SNA shifts economic risk to residential and small commercial customers, S&P believes that PGE continues to be exposed to a significant amount of economic risk. This will be discussed further in Section 5, which examines the effect of Schedule 123 on PGE’s risk.

4.5 Discussion of Weather Effects and the SNA

The SNA weather normalizes sales, so that sales fluctuations due to deviations from normal weather conditions are excluded from the SNA deferral calculations. As a general matter, we have been opposed to the removal of weather effects from decoupling mechanisms, based on three objections:

- Added complexity and reduced transparency;
- The possibility of biased deferrals (i.e., that tend to favor either PGE or its customers) if the normal weather definition used to set rates does not accurately reflect average weather conditions going forward; and
- The lost opportunity to reduce weather risk for both the utility and its ratepayers.

In the case of the SNA, the first issue may not be significant since the method used to weather normalize sales matches the method used to adjust test-year sales to represent normal weather conditions when setting rates.

The second issue relates to the fact that if historical “normal” weather conditions do not match “normal” weather conditions going forward (e.g., because of climate change), the deferrals will be skewed toward either PGE or its ratepayers. For example, if the normal weather conditions during summer months are set “too low” (i.e., assuming fewer CDDs than the going-forward average), PGE will tend to benefit from the weather normalizations in the SNA.[31]

The most significant issue is that excluding the effects of weather variability in the SNA misses an opportunity to reduce risk for both PGE and its ratepayers. That is, in an unusually hot summer (or cold winter), PGE will over-recover its fixed costs at the expense of its ratepayers. Conversely, in an unusually mild summer or winter, PGE will under-recover its fixed costs to the benefit of its ratepayers. If the decoupling mechanism removes the possibility for the utility to over- or under-recover, it also removes the possibility that ratepayers will over- or under-pay for fixed costs.

The only complicating factor is that the decoupling deferrals affect rates in the following year, such that customers do not experience the benefit of the weather risk mitigation in real time (they benefit over the course of one to two years). If a mild weather year (which would produce a rate increase through the SNA) is followed by a hot summer or cold winter, the inclusion of weather in the SNA would have the potential to exacerbate customer risk by increasing rates during a year in which weather conditions are producing increases in customer bills. We evaluated the potential for this to occur using Schedule 7 data from 2002 through 2012.

PGE provided us with monthly billed sales with and without weather normalization, which we consolidated into annual values. Column 1 of Table 4.4.5 shows the weather normalization amount expressed as a percentage of total sales. For example, in 2002 the deviation from normal weather conditions caused sales to be 0.3 percent lower than they otherwise would have been. In the absence of the SNA, this leads to lower utility revenue toward fixed costs. With the current SNA, nothing changes because the effect of weather is removed from deferrals. However, if weather effects are included in the SNA deferral, the result would be an increase in rates in 2003 to account for lower than expected sales in 2002.

Columns 2 and 3 attempt to approximate the class-level bill change (relative to the bill in normal weather) under two circumstances: excluding weather effects from the SNA (which, in this case, is the equivalent of having no SNA at all), and including weather effects in the SNA. In column 2, we assume that the bill change is 90 percent of the change is sales, based on an approximate amount of revenue collected from volumetric rates versus the monthly customer

[31] To see this, consider an unusually hot summer month. If the normal weather definition is too mild, the metered sales will be adjusted too far down, creating a larger SNA surcharge than would have been produced under the “true” normal weather definition. Similar examples can be constructed for winter months.

charge. In column 3, we combine the current-year effect in column 2 with the decoupling deferral from the *previous year* (because the SNA deferral does not affect rates until the following year). We assume that 50 percent of Schedule 7 revenue is affected by the SNA.

If it is the case that mild weather years are consistently followed by hot summers (or cold winters), we would expect the inclusion of weather effects in the SNA deferrals to add to the variability of the annual bill changes. The bottom-most column of the table shows that this is not the case, with the standard deviation of the bill changes being reduced from 1.5 percent to 1.4 percent as weather effects are included in the SNA. Note that in both cases, the average percentage bill change is zero percent, which indicates that the normal weather measures properly reflected the average weather that occurred during this time period.

Table 4.4.5: Effect of Weather Fluctuations on Schedule 7 Bills

Year	Weather Normalization as % of Billed Sales	Bill Change Excluding Weather Effects	Bill Change Including Weather Effects
	(1)	(2)	(3)
2002	-0.3%	-0.3%	
2003	-2.3%	-2.1%	-1.9%
2004	-2.4%	-2.2%	-1.0%
2005	-1.1%	-1.0%	0.2%
2006	0.3%	0.3%	0.9%
2007	1.0%	0.9%	0.8%
2008	1.4%	1.3%	0.8%
2009	2.3%	2.1%	1.4%
2010	-0.4%	-0.3%	-1.5%
2011	2.0%	1.8%	1.9%
2012	-1.0%	-0.9%	-1.8%
Standard Deviation		1.5%	1.4%

Note that utility and customer risk can be further reduced at the cost of some additional complexity. That is, monthly customer bills could be adjusted for the expected effects of weather on fixed cost recovery, with the decoupling true-up occurring at the end of the year. For example, in a hot summer month, the weather adjustment would slightly reduce customer bills to compensate for the over-recovery of fixed costs. The billed revenue following this adjustment would be used in the monthly decoupling deferral calculations (in order to account for non-weather effects).

OPUC Staff has expressed concern that including weather effects in the SNA would "decrease the customer incentive to invest in weatherization improvements." We do not find this to be a compelling argument. The primary reason is that decoupling does not adversely affect customer-level incentives to engage in conservation or energy efficiency. That is, the SNA deferral generated from the conservation of any one customer is spread across all customers in the class, creating a "free rider"-like situation. Since the customer's decision to conserve will not affect the rate it pays, the presence of the SNA should not change its incentive to pursue conservation. The Oregon Commission agreed with this view in Order 09-020, even expanding on the argument (correctly, we believe) as follows: “an individual customer’s action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide *more* incentive for an individual customer to become more energy efficient.”[32]

4.6 Discussion of LRRA Design Issues

In Section 7, we describe the feedback that we received from various stakeholder groups. In this section, we address two objections to the LRRA that Kroger conveyed to us. The first is that Direct Access customers who commit to purchasing generation services from non-PGE energy service providers for five years (e.g., Schedule 485 customers) should be exempted from the generation component of the LRRA since they do not face this charge under their standard tariff. This appears to be a reasonable concern. Our review of the methods used to set the dollar per-kWh LRRA adjustment charge is that PGE does not over-recover due to this concern, as it excludes Direct Access sales from the calculation of the generation services charge. However, it does appear to be the case that the current methods cause cross-subsidies between Schedules 485 and 489 and the other LRRA-applicable rate schedules (because all rate schedules pay the same per-kWh LRRA charge). Therefore, we recommend removing the generation component from the LRRA charge for Schedules 485 and 489.

The second concern raised by Kroger is that the LRRA allows the utility to recover lost revenues due to conservation, but does not account for “found revenues” due to increases in sales from other sources. That is, the “found revenues” result when increases in sales above test-year levels lead to over-recovery of test-year fixed costs because of the recovery of fixed costs through volumetric rates. Under standard ratemaking, the utility does not give these added revenues back. Kroger proposes that PGE only be allowed to recover lost revenues from ETO programs for sales reductions below test-year levels (i.e., the minimum of the estimated ETO sales reductions and the amount by which PGE’s sales are below test-year levels).

Our objection to this proposal is that it assumes that PGE does not face a disincentive to promote ETO’s conservation programs. That is, in the absence of the LRRA, PGE is made worse off by successfully promoting the ETO’s programs, regardless of whether PGE is in a position of total over- or under-recover of fixed costs. Kroger’s proposal limits the ability of the LRRA to meet the objective of resolving the utility’s incentive problem, such that the utility will only have its disincentive removed when total sales are at or below test-year levels (at which point PGE will be paid under the LRRA in the same manner as currently designed). When sales are above test-year levels, PGE will lose revenue when it succeeds in promoting the ETO’s programs.

Finally, Staff recommended that we evaluate the inclusion of energy savings due to the LED conversion of street lights, as introduced in Advice No. 12-17. Staff notes that the policy has not

[32] Order 09-020, page 28.

yet resulted in decoupling deferrals, though they are expected to be included in the 2014 decoupling tariff.

Our understanding is that PGE is converting its existing high-pressure sodium (HPS) streetlights with LED streetlights, which are expected to use approximately 60 percent less energy than the equivalent HPS fixture. Although the streetlight tariffs contain per-kWh charges, usage on these tariffs (Schedules 91 and 95) is not metered. Rather, usage is calculated from the fixture's wattage and the estimated number of operating hours (from sunrise/sunset tables).

HPS lighting is covered under Schedule 91 and LED lighting is covered under Schedule 95. The two tariffs have identical volumetric rates for distribution, transmission, and generation services. According to Advice No. 12-17, the Schedule 123 LRRA adjustment is calculated as "the difference in the amount of energy used by each streetlight being converted, then multiplying that cumulative amount by the fixed amount in the energy charges." We interpret the "fixed amount in the energy charges" to mean the LRRA charge applied to all LRRA-eligible customers.

The appropriateness of the application of Schedule 123 to LED streetlights depends upon how the Schedule 95 rates were established. Because its rates are identical to those of Schedule 91, it appears that the volumetric rate levels were established based on the cost to serve (and sales to) HPS fixtures. Provided that the fixed costs associated with serving LED streetlights is similar to those of HPS streetlights (which appears to be a reasonable assumption), then the treatment of LED streetlights in Schedule 123 is appropriate. That is, rates would have been designed under the assumption that PGE would experience the higher sales from HPS streetlights. Had it designed its rates under the assumption of the lower usage levels of the LED streetlights, the streetlight rates would have been higher. Therefore, crediting PGE for the lost revenues associated with conversions should provide them with a level of fixed cost recovery consistent with the level of revenue allowed in the rate case.

Alternatively, if the Schedule 91 and 95 volumetric rates were designed under the assumption that some LED fixtures would be in place (hence reducing sales relative to using only HPS fixtures), the LRRA deferrals should be calculated in comparison to the level of LED sales assumed when setting rates (i.e., producing LRRA deferrals only when LED energy savings exceed the level assumed when setting rates). However, our interpretation of the information provided to us indicates that PG&E has not included LED fixtures when setting street lighting rates.

5. PGE RISK

5.1 Introduction to the Risk Analysis

This section explores the relationship between decoupling plans and the cost of capital. A commonly advanced position is that by stabilizing revenue flows, decoupling lowers capital risk, and thus the cost of capital for service providers like PGE who have implemented decoupling plans. The core question under investigation is as follows: do quantitative analyses, empirical evidence, and technical studies provide a sufficient foundation to infer that PGE's decoupling plan gives rise to lower cost of capital? If the company's cost of capital is reduced under decoupling, by how much?

We approach the question in three ways. First, we assess the impact of decoupling on the total returns to capital across a sample of decoupled utilities, measured as operating income. Second, we summarize other studies on the effect of decoupling on utility risk. Third, we review reports by credit ratings agencies to obtain their views on the effect of Schedule 123 on PGE's risk.

Of these methods we use, only the third is based solely on data relating to PGE. The statistical analysis of the effect of decoupling on utility risk includes PGE in its sample of 44 utilities (only some of which have revenue decoupling). The outside studies that we review in Section 5.3 evaluate the experience of other decoupled utilities, but were not intended to be evaluations of PGE's specific mechanism or circumstances.

5.2 Relationship between Decoupling and Capital Risk

By removing the revenue effects of non-weather induced sales fluctuations on revenues, the SNA would appear to stabilize the flow of revenue to cover short-run fixed costs. For most utilities, lower (higher) sales levels result in a corresponding decline (rise) in operating income and shareholder returns. As a consequence, energy policy focused on conservation may not be incentive compatible with the profit objectives of privately held utilities. By preserving revenue flows, particularly under the condition of declining sales quantities, decoupling mitigates (or possibly resolves) the tension between policy goals and revenue and profit objectives of service providers.

At the most general level, risk refers to uncertainty—essentially, the variation or range of potential future outcomes. Risk is inherent to all resource commitments affected by uncertain future outcomes. For capital resources, the relevant risk metric is the variation in prospective returns. Risk associated with future returns is determined by many factors including business risk, which in turn cover a host of events and phenomena that impact observed and expected variation in operating income—the accounting returns to capital invested in the main function(s) of the firm.

Relevant short-term business risks can include performance of the regional economy, revenue coverage of varying fuel charges (variable costs), storm activity, and the routine impact of weather on sales quantities. Long-term business risks can include the effects of rising fixed costs (charges on investment, fixed O&M) associated with serving existing or new customers, and increased peak demands. In addition, capital investment for facility replacement and environmental compliance and regulatory governance are often cited as a factor of business risks.

In summary, the focus of the analysis is whether decoupling plans affect business risks, and thus the cost of capital. Under decoupling, business risks, including operating income and equity returns, could be altered by reducing the variation in returns to book capital. Because variation in book returns is positively associated with capital risks, lower variation seemingly reduces capital risks and thus the cost of capital, other factors constant. We measure PGE's risk as the *variation in operating income*, stated as the standard deviation of normalized operating income.

The analysis is conducted using a sample of 44 electricity service providers, some of which have a decoupling plan in place for a portion of the analysis period. Table 5.2.1 lists the sampled utilities, along with some descriptive information.

Table 5.2.1: Utilities included in the Analysis Sample

Utility	Decoupling Docket	Decoupling Date	Other Stabilization Mechanism?	Related Gas Operations?
Alabama Power Company			X(1)	
Avista Corporation				X
Appalachian Power Company			X	
Baltimore Gas and Electric Co.	Letter Order	Nov 2007		X
Central Hudson Gas and Electric	09-E-0588	Jun 2009		X
Cleco Power LLC			X(1)	
Connecticut Light and Power			X	X
Consolidated Edison Co. of New York	07-E-0523	Mar 2008		X
Consumers Energy Company	U-15045	Nov 2009		X
Dayton Power and Light Company				
Delmarva Power & Light Company	C-9093	Jul 2007		
El Paso Electric Company				
Empire District Electric Company			X	
Idaho Power Corporation	IPC-E-04-15	2007	X	
Indiana Michigan Power Company			X	
Interstate Power and Light Company				X
Kansas City Power and Light Company			X(2)	
Massachusetts Electric Company	DPU-0939	Nov 2009		X
Narragansett Electric Company				X
New York State Electric & Gas Corp.	09-E-0715,0716	Sep 2010		X
Niagara Mohawk Power Corporation	10-E-0050	Jan 2011		X
Northern States Power				X
NorthWestern Energy	D2009.9.129; D2007.7.82	Dec 2010		X
Oklahoma Gas and Electric Company			X	X
Orange and Rockland Utilities, Inc	07-E-0949	Jul 2008		X
Pacific Gas and Electric		1980s		X
Portland General Electric Company	UE-215	Jan 2009		
Potomac Electric Power Company	C-9092	Jul 2007		
Public Service Company of Colorado				X
Public Service Co. of New Hampshire				X
Public Service Co. New Mexico				
Public Service Co. of Oklahoma				X
Puget Sound Energy Inc.				
San Diego Gas & Electric Company		1980s		X
Southern California Edison Co.		1980s		
Southern Indiana Gas & Electric Co.				X
Tampa Electric Company				
Tucson Electric Company				X
United Illuminating Company	08-07-04	Jan 2009		
Western Massachusetts Electric Co.	DPU-10-70	Jan 2011		X
Westar Energy, Inc.				X
Wisconsin Power and Light Company				X
Wisconsin Public Service Company	6690-UR-119	Dec 2008		X

The sampled utilities include electric-only utilities such as Dayton Power and Light (a subsidiary of AES Corporation), Idaho Power Company, and UIL Holdings as well as utilities which have substantial gas operations, non price-regulated business activities, or are part of larger holding companies. Examples include Consumers Energy which has sizable gas operations; Alabama Power, subsidiary of Southern Company; Appalachian Power, subsidiary of American Electric

Power; and San Diego Gas and Electric, subsidiary of Sempra Energy, also with large gas operations.[33]

For each utility, we determined the year (if any) in which they implemented a revenue decoupling mechanism. Three sources were used to determine this:

- "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations", by Pamela Morgan of Graceful Systems, LLC (December 2012).
- "State Electric Efficiency Regulatory Frameworks", by the Institute for Electric Efficiency (July 2012).
- Direct testimony of R. V. Hevert on behalf of Potomac Electric Power Company before the Public Service Commission of the District of Columbia, Docket FC-1103, Exhibit PEPCO B-8 (March 2013).[34]

The risk measure, *variation of operating income*, is calculated for each sampled utility using FERC Form 1 data collected for 1993 through 2011.[35] As mentioned above, provided that changes in revenues and costs are not perfectly correlated, variability of revenue is reflected directed within operating income.[36] For electric utilities, a high share of total cost is fixed for the reporting period and, at least arguably, all but the *very long run*. As a consequence, variation in revenue translates into variation in operating income. This is clearly the case for all utilities except perhaps those that have implemented broadly defined cost trackers or formula rates. Operating income constitutes the return on capital (physical assets) committed by investors to utility operations—i.e., for the convenience and necessity of the public. To the degree that decoupling mitigates the variation in operating income, business risks and thus capital risks would seem to be reduced.

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[33] It is important to recognize that, while the above sample is arguably of adequate size and sufficiently representative of industry-wide experience, it does not incorporate all power systems. Notable large and comparatively small systems not incorporated in the analysis include Allete Incorporated; Ameren Corporation; Black Hills Corporation; CenterPoint Energy, Inc.; Dominion Resources, Inc.; Central Maine Power; DTE Energy Company; Duke Energy Corporation; Entergy Corporation; Exelon Corporation; FirstEnergy Corporation; MGE Energy, Inc., NextEra Energy, Inc.; NV Energy, Inc.; Otter Tail Corporation; Pinnacle West Capital Corporation; PPL Corporation; Public Service Enterprise Group Incorporated; Scana Corporation; and Wisconsin Energy Corporation. In virtually all cases, these predominantly larger power systems do not have subsidiaries with decoupling plans in place (e.g., Ameren Corporation, DTE Energy, Scana Corporation). In the case of Central Maine Power, subsidiary of Iberdrola, a price cap plan has been in place for some time. Beginning in 2009, Puget Sound Energy has been privately held by foreign investors, Macquarie Group.

[34] Mr. Hevert lists Regulatory Research Associates as the source of the information contained in his exhibit.

[35] The FERC Form 1 reports originate from 1938, and are currently available electronically for the 1993-2011/12 timeframe. Form 1 reports cover virtually all privately held retail electricity service provides across the U.S.

[36] It is useful to mention that operating income can vary, either up or down, for any number of reasons unrelated to changes in sales quantities and revenue. Examples include changes in corporate tax rates, rates of book depreciation, insurance charges, or unexpected changes operating expenses. Of real concern would be the transfer of the investment costs associated with the construction of sizable new facilities from construction to plant-in-service.

The analysis procedures are as follows. First, annual operating income for each utility is normalized by the utility's capital, measured as "book assets." Book assets are calculated as year-end gross plant minus accumulated depreciation and construction work in progress (CWIP), plus regulatory assets. This measure of book capital is essentially a rate base proxy. Normalization of operating income is necessary, as the sampled utilities vary substantially according to size, the intensity that capital is employed within the process of delivering services, and growth in the underlying capital stock and perhaps driven by changes in resource mix over time and changes in book interest costs.[37,38] The net result of this procedure—operating income normalized by book assets—is similar to return on rate base.

We then calculate the standard deviation of the normalized operating income across every three year window from 1993 through 2011 (e.g., 1993 to 1995, 1994 to 1996, etc.).[39] As a sensitivity analysis, results are reported with and without the investor-owned utilities (IOUs) from California (PG&E, SCE, and SDG&E), as these utilities have had unusual experiences in a couple of ways (extreme wholesale market prices during the deregulation crisis around the turn of the century; and an unusually comprehensive combination of decoupling mechanisms and other cost trackers).

Figures 5.2.1 and 5.2.2 illustrate the normalized operating income and its 3-year standard deviation (respectively) for three sets of utilities: those that have had decoupling at any time during the sample timeframe (excluding the California IOUs); those that have never had decoupling; and PGE.

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[37] Other rate base proxy definitions are plausible and, for two reasons, the measure used here will certainly contain some degree of error. First, fuel stocks, stores inventory, and accumulated deferred income taxes are excluded from the proxy, and there is no attempt to account for working capital. Second, some utilities included some share of construction work in progress within the rate base in lieu of capitalizing interest on construction. Third, at a detail level, rate base definitions evolve through time.

[38] There may be reason to reflect costs in real terms if historical inflation varies significantly over the historical period. Real terms would be warranted under two conditions. First, if there are substantial differences in asset growth across the utilities. For utilities with fast rising gross assets due to grow or other reasons, the cost rate for long-term outstanding debt will follow current debt yields more closely than utilities where assets are changing slowly. Such differences show up in book interest costs, and thus observed and required normalized operating income. The ample supply of capital with respect to demand, augmented significantly by the monetary policy of the U.S. Federal Reserve beginning in November 2008 and referred to as quantitative easing. As a result, comparatively fast asset growth can cause book interest costs to decline. For this reason, the coefficient of variation of operating income is used in addition to standard deviation of normalized operating income.

A second condition is differences in the underlying rate of inflation across U.S. regions. All evidence suggests that this is not the case.

[39] We conducted a sensitivity analysis using the standard deviation calculated across 5 years. The results were qualitatively the same as those presented here.

Figure 5.2.1: Average Normalized Operating Income by Utility Type

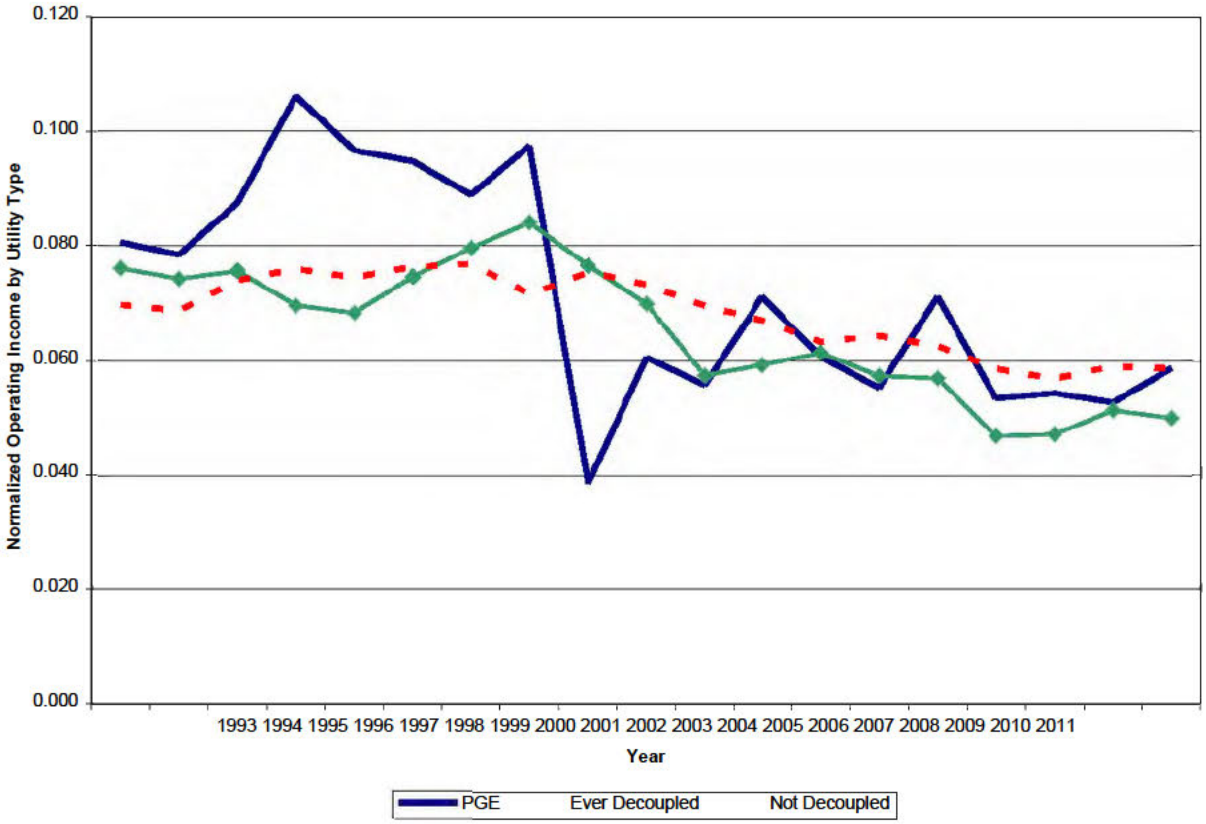
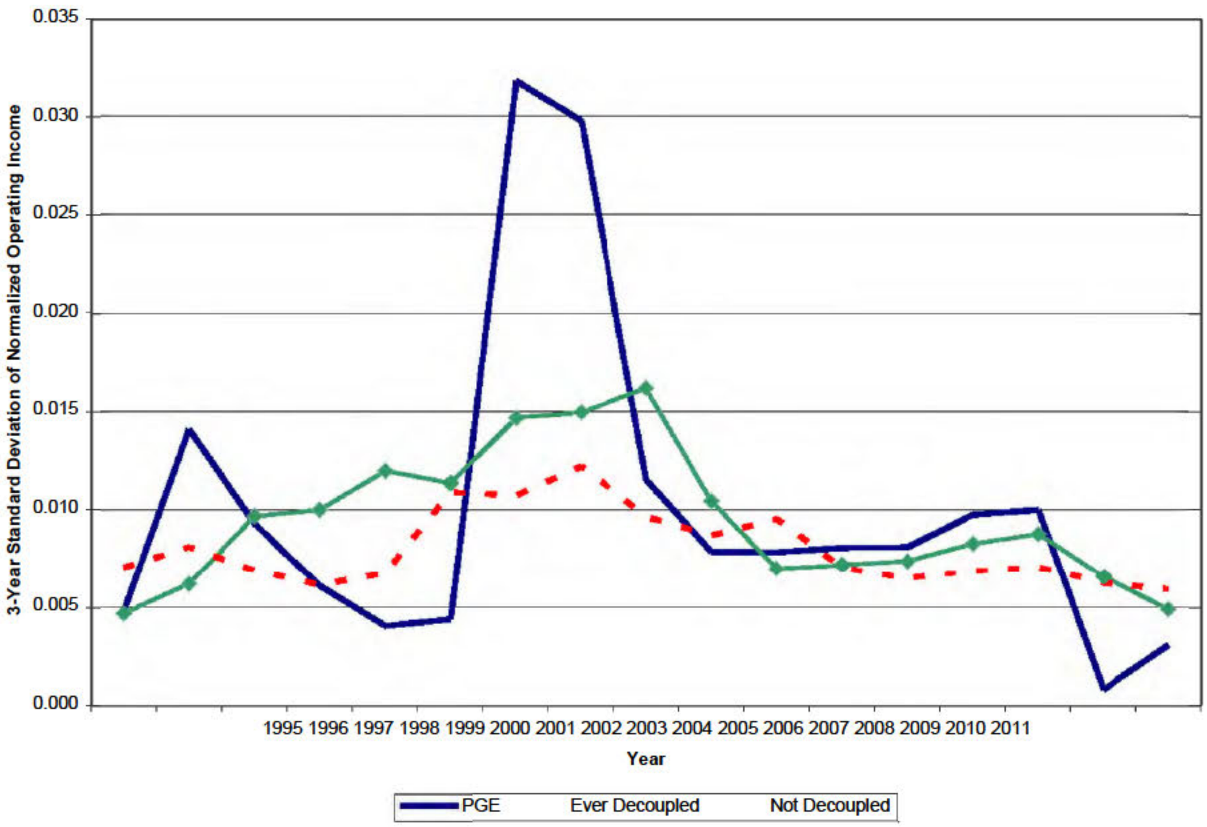


Figure 5.2.2: Three-year Standard Deviation of Operating Income by Utility Type



Some observations on these figures:

- PGE appears to have more variable returns than the other utilities, but this is just an artifact of comparing a single utility to an average of utilities (15 ever-decoupled utilities and 25 never-decoupled utilities).
- For all utilities, the level and variability of returns declines sometime after the year 2000.
- The variability of PGE's returns appears to stabilize beginning in 2008, at a level that is somewhat low compared to the returns in previous years.[40] While Schedule 123 may contribute to this reduction in variability, the effect starts too early for this to clearly be the case. Note that PGE also had its Annual Power Cost Update and Annual Power Cost Variance Mechanism (Schedules 125 and 126) approved just before the beginning of this period of reduced variation in returns. These mechanisms are more likely to have contributed to the reduced variation in returns (to the extent that the observed outcomes are not just due to random variations in returns).

[40] In Figure 5.2.1, PGE's returns become fairly constant at approximately 5.4 percent. In Figure 5.2.2, the relatively constant returns are reflected in the somewhat steep decline in the standard deviation from 2009 to 2010.

The utilities grouped in the "ever decoupled" category implemented their mechanisms on different dates, making it difficult to infer the effect of decoupling from these figures. In addition, there are other relevant characteristics of utilities that are not accounted for in the figures, including the presence (or nature) of cost trackers. In order to properly account for the different decoupling start dates and other firm- and time-specific effects, we estimated a statistical model to determine whether the implementation of revenue decoupling is associated with a reduced variation in utility returns.

Specifically, we estimated a statistical model that attempts to explain the three-year standard deviation of normalized operating income as a function of three explanatory factors:

- Utility fixed effects, which control for utility characteristics that do not change over time;[41]
- Fixed year effects, which control for factors that may affect utility operating income in each three-year window (e.g., economic conditions); and
- The presence of revenue decoupling, calculated as a moving average across the three-year window.[42,43]

Because some utilities implement decoupling during the timeframe while others do not, this method can be interpreted as a "differences-in-differences" estimator. That is, the decoupling effect is estimated as the change in utility "risk" (measured as the variation in operating income) following the introduction of decoupling, compared to the risk level experienced by the utility prior to decoupling and the level of risk experienced by all utilities (with or without decoupling) in each year.

The statistical model is formally described in Equation 5 and Table 5.2.2.

Equation 5:

$$VOI_{c,t} = a_c + b_{Decouple} \times Decouple_{c,t} + \sum_{i=1996}^{2011} b_i \times Year_{i,t} + e_{c,t}$$

[41] For example, utility fixed effects may control for utility size or regulatory environment.

[42] For example, if the utility had decoupling in all three years, the value of this variable is unity. If the utility had decoupling during only one of the three years, the value is 1/3. Note that this indicator variable does not account for design differences across decoupling mechanisms, such as whether the effects of weather are included in the deferrals.

[43] We conducted a sensitivity analysis using the 1-year and 2-year lags of the decoupling indicator to account for the fact that decoupling deferrals affect utility revenues with a lag. The use of these alternative decoupling indicators does not affect the reported results. In conjunction with this, we examined an alternative dependent variable that is based on the three-year moving average of the normalized returns. That is, because decoupling deferrals affect utility revenues with a lag, the year-to-year returns could be exacerbated by decoupling even if longer-term returns are made more stable. We evaluated this moving average in the same manner as the single-year outcome: by calculating the three-year standard deviation of the variable and including it has the left-hand-side (dependent) variable in the regression model. These specifications (including current and lagged decoupling indicators) do not provide any evidence of a link between decoupling and reduced utility risk.

Table 5.2.2: Variables Included in the Statistical Risk Model

Variable Name / Term	Description
$VOI_{c,t}$	Variation of Operating Income for utility *c* in year *t*
a_c	The estimated utility-specific fixed effects
$b_{Decouple}$	The estimated effect of decoupling on $VOI_{c,t}$
$Decouple_{c,t}$	An indicator variable for whether utility *c* is decoupling at time *t*
b_i	The estimated fixed year effects
$Year_{i,t}$	An indicator variable for year *i* at time *t*
$e_{c,t}$	The error term

If revenue decoupling is associated with a reduction in the variability of utility operating income, the analysis would find a negative and statistically significant coefficient on the decoupling variable ($b_{Decouple}$). Table 5.2.3 shows the estimated coefficients on the decoupling variable with and without including the California IOUs. The standard error of the estimate is in parentheses.

Table 5.2.3: Estimates of the Effect of Decoupling on the Variability of Utility Returns

Measure	Full Sample	Excluding Calif. IOUs
Decoupling Coefficient	0.010 (0.009)	-0.0006 (0.002)
Number of Observations	744	693
Number of Utilities	44	41
R-squared	0.10	0.08

In both models, we find no statistically significant effect of revenue decoupling on the variability of utility net operating income. There are a couple of potential explanations for this finding. First, it could be that the effects of decoupling are small in comparison with all of the factors that can affect utility risk. If this is the case, there is little justification for reducing the utility's allowed return on equity (ROE) upon the implementation of decoupling. Second, it could be that the relatively limited experience to date with revenue decoupling has not provided a large enough sample from which to estimate statistically significant effects of revenue decoupling on utility risk. That is, in order to examine risk, we need to be able to observe how the variability of an outcome changes over time.

The amount of data required to be able to adequately examine this effect may exceed the amount of experience that we observe in the current data. Note that a number of the utilities that have decoupling are relatively recent adopters, such that they provide a limited amount of experience from which to infer the effect of the mechanism on risk.

In the next sub-section, we will provide a summary of other studies of the effect of decoupling on utility risk. The findings are consistent with ours, with little indication of a significant effect.

5.3 Studies and Testimony Regarding the Effect of Decoupling on the Cost of Capital

This discussion highlights the expressed views and conclusions reached by others regarding the effect of decoupling on the cost of capital, as expressed in studies and testimony.

Comments by John Reed, Concentric Energy Advisors before the Massachusetts Department of Utilities (DPU Docket 07-50, Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources)

The issue is set up as: "To the extent that decoupling affects investors' required returns, that effect should be reflected in rates, which raises the question of whether an explicit adjustment in ROE is warranted when decoupling is approved." In response, the prepared comments go on to say: "To date, there is no evidence suggesting that investors' required returns are reduced as a result of the approval of decoupling mechanisms. The recent expansion in the use of decoupling mechanisms is in response to significant market changes, and the policy responses to these changes, in the past few years." The discussion cites various incremental changes in the underlying business environment for utilities, then stating: "Decoupling mechanisms are an effective means to offset these incremental risks, but they certainly cannot be viewed as warranting a reduction in allowed returns when the recently-created risks they offset were never previously reflected in rates...Furthermore, there is analytical and anecdotal evidence supporting the position that investors' required returns are unaffected by the implementation of decoupling measures."

The discussion goes on offer empirical evidence, stating: "CEA performed an analysis to compare the price-to-book ("P/B") ratio of utilities that have received approval to implement decoupling mechanisms to the average P/B of a group of peer companies to test for any measurable change in relative valuations.[44] On average, the relative P/B of the utilities receiving approval to implement decoupling did not increase during the month following the approval, when compared to the month preceding the approval."[45]

The discussion continues with conclusions regarding the issues, as follows: "Our analysis and understanding of the markets suggests that investors have developed the expectation that decoupling is the logical way forward to offset recently created incremental risks, and of providing benefits to customers and utilities alike...The significant and growing number of utilities that have implemented decoupling measures and the fact that decoupling mechanisms largely or entirely offset recently created incremental risks, helps explain why the market response to the approval of decoupling measures has been neutral."

"The Impact of Decoupling on the Cost of Capital: An Empirical Investigation" by Brattle Group, March 2011

[44] CEA notes that the analysis controlled for general market movements by creating a P/B Index for utilities.
[45] It isn't clear that this is a proper comparison, either in terms of methodology—i.e., analysis of Price/Book ratios—or the selection of timeframe for evaluation of changes in Price/Book ratios.

This often cited discussion paper uses multi-stage DCF model to assess the impacts of decoupling on the cost of capital. Section 2 of the paper states: "to date, about one-fifth of regulatory decisions that we have reviewed related to decoupling for gas and electric utilities have concluded that decoupling does reduced a utility's cost of capital, and accordingly these decisions have reduced the allowed ROE. The reductions in allowed ROE have ranged from 10 to 50 bps." The Brattle discussion paper succinctly sets up the issue, stating: "Decoupling stabilizes revenues, but net income can still vary. Although depreciation and interest expense are relatively stable, other costs can change quickly between rate cases. At times of rapid capital investment, like the present for utilities that are facing significant environmental retrofits, depreciation and interest may also increase rapidly so that general rate cases are frequently required....A more targeted question is whether decoupling reduces the non-diversifiable risk that determines the cost of capital in financial markets?" The Brattle study rates or scores decoupling plans for some 46 natural gas utilities and then compares "current stock prices with forward-looking forecasts of cash flows from the business." Brattle concludes its analysis as follows: "Our statistical tests do not support the position that the cost of capital is reduced by adoption of decoupling. If decoupling decreases the cost of capital, the tests strongly suggest that the effect must be minimal because it is not detectable statistically."

"Decoupling: Impacts on the Risk of Public Utility Stocks", a Presentation by Richard A. Michelfelder, of Rutgers University and Managing Consultant, AUS Consultants, Delivered before the Society of Utility Regulatory and Financial Analysts

The discussion presents a statistical analysis of the implied impacts of decoupling on equity risk premia for electricity stocks. Like our study, the discussion sets out the problem in terms of variation in operating cash flow (net short-term margin including depreciation/operating income). The analysis focuses on equity market risk premia and includes two risk metrics, including GARCH estimation of share price volatility[46] and systematic risks in the context of Capital Asset Pricing Model. The analysis is monthly in frequency. The study concludes that decoupling mechanisms have no statistically significant effect on the cost of equity capital, for utilities.

"Decoupling Impacts on the Cost of Capital", a presentation by Jim Lazar, The Regulatory Assistance Project, before the Minnesota Public Utilities Commission, April 15, 2008.

The discussion focuses on mechanics of decoupling mechanisms and changes in the overall cost of capital obtained through reduced equity participation in total capital. More specifically, Lazar argues that the mitigation of business risks, facilitated by decoupling, allows for a more intensive use of debt within the capital structure, thus lowering the overall cost of capital, holding the cost rates of debt and equity constant.[47]

[46] Analysis of capital market risks, conducted for the immediate report, also utilizes GARCH methods in order to ferret out impacts of decoupling mechanisms on the cost of capital.
[47] This result is somewhat curious in view of the famous 1958 discussion by Franco Modigliani and Merton Miller (referred to as MM), presented as propositions I and II, show that under defined conditions, the cost of capital to the firm is indifferent to the relative shares of debt and equity within total capital.

"Revenue Regulation and Decoupling: A Guide to Theory and Application", The Regulatory Assistance Project, June 2011.

The report at chapter 10 states: "Decoupling can significantly reduce earnings volatility due to weather and other factors, and can eliminate earnings attrition when sales decline, regardless of the cause..." The report summarizes the expressed view on decoupling and cost of capital as follows: "The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity, but this generally requires many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.

Summary of Studies

In our view the Brattle Group and analysis presented by Richard Michelfelder are viable and provide useful insight. Specifically, unless it can be shown that decoupling mitigates operating income, and such effects translate into observable reductions in equity and debt risk premia, it is prudent to presume that decoupling mechanisms, in isolation of the effects of other risk factors—both those that are increasing and those that are decreasing, have no measurable impact on the cost of capital.

5.4 Credit Rating Reports and Debt Cost Rates

Ratings agencies produce periodic reports on the creditworthiness of companies. In this sub-section, we provide our review of impact of decoupling on debt cost rates based on information extracted from these reports. This evidence includes the assessments of the creditworthiness of the outstanding debt of PGE, as reported by credit rating agencies including Moody's Investor Services, Fitch Ratings, and Standard & Poor's Corporation. Conclusions reached by rating agencies regarding creditworthiness of PGE's outstanding debt can be inferred from the ratings and narratives provided by these agencies. It is useful to review the credit ratings over time and, at a general level, gauge how PGE's credit ratings have been potentially impacted by Schedule 123. For PGE, we summarize the credit ratings of rating agencies in Table 5.4.1, below. The table is augmented with synopsis of rating agency reviews of PGE and its credit worthiness over recent years, 2006-2012.[48]

[48] The immediate study does *not* explore whether differentials in the underlying debt cost rate exist, between utilities with decoupling plans and those without. Addressing the potential for differential risks and resulting debt cost rates would involve the examination of market bond yields for specific maturity dates on outstanding debt issues of highly similar terms (i.e., call provisions, security provisions including the pledge of physical property as collateral for selected issues such as first mortgage bonds). Empirical evidence shows that, for outstanding debt issues, the yield-to-maturity measures of cost rates are not necessarily ordered according to differences in credit ratings by rating agencies.

Table 5.4.1: Summary of PGE Credit Reports by Agency

Agency	Year	Senior Secured Debt	Unsecured Debt, Revolver	Commercial Paper	Outlook
Moody's	2006	Baa1	Baa2	P-2	Stable
	2007	A3	Baa2	P-2	Stable
	2008	Baa1			
	2009	A3	Baa2	P-2	Positive
	2010	A3	Baa2	P-2	Stable
	2011	A3	Baa2	P-2	Stable
	2012	A3	Baa2	P-2	Stable
Fitch[49]	2006	A-	BBB+	F-2	Stable
Standard & Poor's	2006	BBB+	BBB	A-2	Negative
	2007	BBB+	BBB	A-2	Negative
	2008	BBB+	BBB	A-2	Stable
	2009	A	BBB+	A-2	Negative
	2010	A-	BBB	A-2	Stable*
	2011	A-	BBB	A-2	Stable
	2012	A-	BBB	A-2	Stable

* Rating of August 27, 2010.

Review of PGE's Credit Worthiness, by Standard and Poor's[50]

January 31, 2008: S&P cites several strengths favorable to PGE including "An above-average framework for the recovery of capital and power costs that includes: a forecast test year...an annual mechanism to update power costs based on projections; and a power cost adjuster that tracks differences between actual costs and those authorized in rates...". S&P cites weaknesses including, at the time, PGE's sizable capital program, and a weakening of PGE's financial measures including its funds from operations. S&P assigns a BBB+ rating to PGE's secured outstanding long-term debt.

August 26, 2009: The updated outlook is reduced to "Negative" from S&P's rating in 2008, citing PGE's considerable level of expenditure for capital in the near term, as well the effects of the national recession. S&P cites reduced electricity sales, stating "...particularly severe in Oregon, falling electric sales that are pressuring cash flows in 2009 despite a recently approved decoupling mechanism..."

August 26, 2011: S&P continues to rate PGE as investment grade (BBB) but also rates first mortgage bonds as A-. The discussion cites PGE's settled rate case of December, 2010. S&P

[49] Reported April 18, 2006. Fitch suspended further rating of PGE in November of 2006.

[50] Standard & Poor's has issued numerous credit reports for PGE in recent years. This includes comparatively small changes in credit ratings and outlook, as reported a calendar period. As a result, within a year, small differences can be observed from one report to another.

goes on to mention PGE's favorable internal cash and near-term declines in capital requirements. S&P indicates that PGE faces risks regarding the full recovery of the costs of the Trojan nuclear plant. In particular, S&P makes a favorable mention of the renewable energy tracker, the recognition of costs in rates outstanding a standard rate case proceeding.

December 19, 2011: The review cites PGE's continued levels of adequate liquidity, and a favorable business risk profile. PGE's outlook is judged stable, and S&P's investment credit ratings for long-term unsecured debt and short term debt are set at BBB and A-2, respectively.

February 21, 2012: This most recent review by Standard and Poor's reiterates previous assessments: that PGE focuses on its core utility function, and has favorable regulatory governance including near-term recovery (non GRC-based) of power costs. S&P cites credit metrics including funds from operations (FFOs) that closely approximate levels reflected in previous reviews. S&P states: "Debt levels and leverage have remained abut the same since an increase in 2008...If cash flow remains robust, we anticipate debt leverage to improve slightly. However, capital spending may trend higher beyond our outlook horizon as additional mandated renewable energy resources and other infrastructure costs rise." S&P goes on to state: "The stable outlook reflects our anticipation that credit metrics will not materially diminish..."

Review of Credit Worthiness of PGE, by Fitch Ratings
May 11, 2006: Fitch Ratings assigned PGE with a favorable financial outlook (Stable), citing the Company's strong underlying credit metrics. Key elements mentioned within the review include, as cited by Fitch, "constructive" regulatory environment, comparatively low debt ratio (43%), and high liquidity position. Concerns raised during the review by Fitch include, as implied, costs associated with the Boardman Coal Plant outage, and the pending regulatory outcome regarding the remand by Court of Appeals of the PUC decision regarding the recovery of investment costs associated with the Trojan nuclear plant.

Review of Credit Worthiness of PGE, by Moody's Investor Service
August 17, 2007: In summary, Moody's review of PGE's credit risks is quite similar to that of S&P's performance review. Moody's review was published not long following PGE's separation from its previous corporate affiliation. Moody's cites PGE's favorable market context, its industrial sales mix in particular, and fair regulatory governance, stating "We currently view PGE's business and regulatory risk profile as consistent with the high end of the Baa rating category." Moody's mentions the new annual power cost update tariff (PCAM) which "provides a means for rate adjustments to reflect updated forecasts of net variable power costs for future calendar years." Also, Moody's cited PGE's somewhat higher equity ratio, with the stated objective of 50% equity participation in total capital.

June 29, 2010: This credit review update reaffirms PGE's continued stable outlook, though makes mention of weaker credit measures over the previous 15 months. The credit review cites reduced sales volumes attributable to weather and conservation, and the Company's collaborative relationship with the Oregon PUC and PGE's moderate near-term capital program.

June 30, 2011: Once again, Moody's affirms the previously determined credit ratings including Baa2 (Issuer), A3 (secured debt -first mortgage bonds), Baa2 (unsecured debt and revolver), and P-2 (commercial paper). At this time, Moody's cites PGE's comparatively supportive regulatory environment, improved financial results, and diverse resource base. In the review, Moody's mentions the power cost adjustment mechanism (PCAM), renewable resource cost tracker, and revenue decoupling.

March 16, 2012: This brief review cites PGE's supportive regulatory environment. Moody's warns of the potential downward movement in its overall credit ratings for the PGE, should the Company experience weakened internal cash flow.

Summary of Credit Reports

Over the recent years 2006-2012, the credit worthiness of PGE has been gauged by the three major credit rating agencies. The reviews, several of which are cited above, make frequent mention of cost trackers and occasional reference to PGE's recently implemented sales decoupling mechanism. The analysis finds virtually no change in the credit worthiness of PGE over these years, which includes a major change in regulatory governance in the form of cost trackers that cover significant shares of total costs. Particularly in the S&P reports, the impact of PGE's revenue decoupling mechanism on operating income (and internal flow of funds) is portrayed as minor when compared to the effects of the Company's PCAM cost tracker. Accordingly, revenue decoupling appears to have not significantly affected PGE's debt costs.

6. PGE BEHAVIOR

The fifth required area of analysis calls for an exploration of the changes in PGE's "culture or operating practices resulting from the implementation of the partial decoupling mechanism." In this section, we review a variety of aspects of PGE's behavior, including marketing materials, advertising expenses, customer satisfaction surveys, and reports of activities related to energy efficiency and conservation going back to 2006.

A recurring theme in this section is that it is difficult to attribute specific changes in PGE's behavior (or changes in measures affected by PGE's behavior) to the implementation of Schedule 123. Other factors affecting PGE occurred in a similar timeframe, including the passage of Senate Bill 838 (SB 838) in 2007, which allowed for additional funding to support conservation and energy efficiency. While we observe increases in ETO program performance and conservation program funding in the ensuing years (including the years following the introduction of Schedule 123 in 2009), we have no way of knowing what would have occurred in the absence of Schedule 123. While the increase in ETO funding is most certainly attributable to SB 838, would program performance for PGE customers have suffered in the absence of the SNA and LRRA? As we will describe later in the report, the ETO has told us that its program performance improves when they have the utility as a partner, but even they have a difficult time determining the extent to which Schedule 123 produced changes in PGE's behavior.

6.1 Operating Practices

In response to our data request regarding PGE's internal policies and procedures, PGE provided the following.

Labor Compensation Practices and Policies
PGE has not implemented any changes in labor practices and policies directly resulting from the implementation of the SNA or LRRA.

Organizational Changes (e.g., the allocation of staff across company functions)
PGE has hired several employees to provide outreach to customers concerning the energy efficiency and conservation programs. The funding for these employees and associated promotional expenses is provided through Schedule 110 Energy Efficiency Customer Service.

Customer Service Resources and Practices
PGE has multiple channels available in which residential and business customers may contact the Company with inquiries about energy efficiency. These include telephone, email, mobile devices, community offices, and U.S. mail. PGE is the first stop for many customers who have inquiries about consumption, what, if any, tools are available to help to reduce their usage, as well as energy efficiency options and energy audits.

Customer Service Representatives (CSRs) and Business Team Energy Experts are trained to assist customer with their inquiries and engage in fact finding questions wit h the customer. If CSRs are unable to troubleshoot and resolve the customer's inquiry, customers are referred to the ETO for assistance and additional information relating to incentives and energy efficiency. PGE CSRs either fill out a consultation request which is passed to the ETO, which in turn contacts the customer to discuss further or set up an appointment, or the call is transferred to the ETO.

PGE also has outreach programs designed to inform and educate customers about EE through brochures and collateral materials, community and business forums, as well as internal Energy Expert resources that are available to assist customers about consumption, energy efficiency options, and areas for potential upgrades for efficiencies through ETO involvement.

In 2012, PGE implemented a new customer self-service tool called Energy Tracker that is available through a secure site accessed through PGE's web site. This tool provides tips related to usage and ways customers can save energy.

CA Energy Consulting Commentary
Of the responses provided by PGE in this section, the change that appears to be the most consistent with decoupling is the introduction of the Energy Tracker, which is an on-line tool that provides customers with detailed information about their usage and ways in which the customer can conserve. In theory, this kind of effort is enabled by revenue decoupling (e.g., the SNA), but not by alternatives such as the LRRA. That is, the Energy Tracker provides customers with information that may lead them to conserve, but does not necessarily result in easily

measured savings. In order for PGE to recover lost revenues under a mechanism such as the LRRA, the energy savings must be measured and attributed to a specific ETO program. This is not the case for the SNA, as the lost revenues associated with *any* reduction in sales (except those caused by deviations from normal weather) regardless of the source. Because of this, the SNA removes PGE's disincentive to offer "informational" programs such as the Energy Tracker, whereas the LRRA does not. Of course, it is possible that PGE would have offered the Energy Tracker in the absence of the SNA.

6.2 Rate Design

Revenue decoupling can change the utility's incentive to pursue certain rate design objectives that are viewed as being consistent with conservation objectives. For example, the utility may support lower monthly customer charges, thereby shifting revenue toward volumetric rates and increasing customer-level incentives to conserve. In addition, the utility may support steeper block pricing structures (e.g., increasing the rate for usage in excess of 1,000 kWh per month relative to the rate for the customer's first 1,000 kWh) in an attempt to discourage customers from using more energy. In the absence of decoupling, both of these rate design changes increase the variability of utility revenues in response to changes in sales. By reducing or removing the link between sales and revenue, decoupling can mitigate the effect of these rate design changes on the variability of utility revenues.

Because the SNA does not account for the effect of weather on sales, PGE does not receive the same amount of stability in sales as it would under a "full" decoupling mechanism (i.e., one that includes the effects of weather). This may explain the rate design proposals that PGE has put forth in UE-215 and UE-262. Our review of the rate design testimony from UE-215 and UE-262 indicates that the presence of the SNA did not appear to affect PGE's proposed rate design for Schedules 7 and 32. In its proposed residential rate design within UE-215, PGE gave most of its attention to modifying the size of the initial usage block, which had been 250 kWh. PGE initially proposed a three-block structure (0 to 500; 501 to 1,000; and over 1,000 kWh), while the case resolved with a two-block structure with a 1,000 kWh break point. PGE does not propose to increase the share of revenues collected in the second block in its UE-262 testimony. (Alternatively, it proposes to maintain a 0.722 cents/kWh difference between the first and second block prices.)

PGE agreed to, but did not propose, a decrease in the single-phase customer charge from $10 to $9 per customer month. In UE-262, PGE is proposing to increase this charge back to $10 per customer month, but to simultaneously decrease the three-phase customer charge from $14 to $10 per customer month. (In testimony, PGE supports this change on the basis of tariff simplicity and the fact that very few Schedule 7 customers take three-phase service.)

In summary, we do not find evidence that PGE factored the presence of the SNA into its rate design proposals. Perhaps this is not surprising given that the SNA does not cover weather-induced fluctuations in sales. If OPUC and other stakeholders believe that rate designs with lower customer charges and higher tail-block prices help encourage conservation, we would recommend altering the SNA to include the effects of weather in its adjustments, perhaps under the condition that the rate design changes are implemented.

6.3 Support for Conservation Programs

In Oregon, the ETO is responsible for administering conservation and energy efficiency programs. However, there is still a role for utilities to work with the ETO to increase awareness of and participation in the ETO's programs. One way to evaluate the effect of the SNA and LRRA on PGE's behavior is to examine changes in their work with the ETO across time.

Unfortunately, it is difficult for us to ascribe such changes to the introduction of Schedule 123. The primary reason for this is that energy efficiency and conservation program funding increased substantially over our relevant timeframe (beginning in 2006) due to SB 838. It is also important to note that the ETO attributes some of its success in conservation to the fact that PGE is a very active partner, and believes that PGE's commitment to the programs is helpful in achieving its goals.[51] Therefore, we believe it is worthwhile to provide an overview of the activities PGE has engaged in that demonstrate its support for conservation programs, despite the difficulty in attributing those activities to Schedule 123.

Table 6.3.1 shows annual incentives paid to PGE customers for energy efficiency activities and energy efficiency savings achieved by PGE customers (aMW) from 2006 to 2012. Energy savings from efficiency have grown in all years except from 2007 to 2008, which saw a steep one-time decline in savings from industrial customers. Incentives paid to PGE customers have more than tripled since 2006, but have steadily remained between 35 and 40 percent of ETO's total incentives paid.[52]

Table 6.3.1: Incentives Paid to and Conservation Achieved by PGE Customers[53]

Year	Incentives paid to PGE Customers ($000)	PGE Energy Efficiency Savings (aMW)
2006	10,565	14.1
2007	11,006	22.5
2008	15,479	18.6
2009	20,836	20.4
2010	26,665	25.6
2011	33,470	28.2
2012	36,626	32.2

[51] Section 7 of this report provides details of our interview with Margie Harris, the Executive Director of the ETO.
[52] The ETO also pays energy efficiency incentives to customers of Pacific Power, NW Natural, Cascade Natural Gas, and Avista.
[53] Statistics taken from ETO annual reports produced to the OPUC from 2006 to 2012.

Even though gains in efficiency and conservation may not be attributable to the SNA or LRRA, PGE's support for the ETO and advocacy for increased funding to the ETO may be the result of decoupling incentives. PGE states that "Schedule 123 has significantly alleviated concerns that PGE otherwise would have had regarding the negative impacts on fixed cost contributions that result from increased energy efficiency funding to the [ETO]."

PGE also points out that they have devoted additional resources to conservation outreach. Specifically, through funding provided by Schedule 110, PGE hired several employees and paid for associated promotional advertising. Again, while these activities cannot be directly attributed to decoupling, PGE may have been less willing to commit these resources in the absence of Schedule 123.

Funding for energy efficiency activities is also provided by SB 838. A detailed summary PGE's efforts supported by that funding can be found in ETO annual reports beginning in 2008. The timing of SB 838 (approved for PGE in the second quarter of 2008) and variations in reporting conventions make it difficult to perform a before-and-after comparison of activities with respect to decoupling. It is clear, however, that PGE engaged in conservation outreach prior to 2009 and that those efforts continued or expanded thereafter. Tables 6.3.2 and 6.3.3 contain descriptions of PGE's activities in support of the ETO in 2008 and 2012, respectively.

Table 6.3.2: PGE Support for the ETO, *2008*

Category	Activity
General	Assigned PGE liaison to Energy Trust
	Coordinated with ETO and other utilities on joint ad campaign
Commercial	Launched "Save More, Matter More" energy efficiency campaign urging business customers to make a pledge to save energy
	Included three efficiency ads in fall ad campaign
	Added EE case studies to PGE Web site
	Made over 50 presentations organizations
	Generated 72 qualified leads to the ETO
Industrial	Added manufacturing case study to PGE Web site
	Targeted small industrial customers for "Save More, Matter More"
Residential	Included ETO program information in 8 of 12 monthly *Update* newsletters
	Launched On-line Energy Analyzer
	Fielded EE advertising on television and other media

Table 6.3.3: PGE Support for the ETO, *2012*

Category	Activity
Commercial and Industrial	Featured energy efficiency articles and tips in several editions of *Energize*, quarterly bill insert, and *Business Connection*, bi-monthly e-newsletter
	Launched fifth annual "Save More, Matter More" campaign resulting in 487 requests for free energy consultations and 71 qualified leads to the ETO
	Engaged in several direct mail EE ad campaigns
	Three dedicated Outreach Specialists engaged in consultations, customer calls, presentations, and various other activities
	Outreach Specialists generated 550 qualified leads to ETO
Residential	Featured energy efficiency articles and tips in several editions of *Update*, monthly bill insert, and *Home Connection*, bi-monthly e-newsletter
	Delivered 141,531 Energy Saver Kits to PGE customers
	Distributed free showerheads and compact fluorescent bulbs
	Weatherized homes
Heat Pump Activity	Conducted three 2-month heat pump promotions resulting in 390 leads to PGE-approved contractors
	Funded and facilitated two training sessions for contractors to learn about the ETO's ductless heat pump program guidelines

Our evaluation of the ETO reports is that PGE's activities in support of ETO expanded over time. However, we cannot determine whether this is due to increases in overall funding levels due to SB 838, a change in PGE's reporting conventions across years, or a change in PGE's behavior due to a reduction or elimination of its disincentive to promote conservation and energy efficiency.

6.4 Marketing Activities

Decoupling may affect a utility's priorities with respect to the allocation of advertising expenses. Decoupling is most often thought of as a means to remove the utility's disincentive to promote conservation and energy efficiency. In this case, the utility may shift its marketing efforts more toward advertising that promotes these programs. A less commonly cited effect also occurs, which is that decoupling reduces the utility's incentive to promote programs that *increase* use per customer, as the revenues gained from those efforts would be returned to customers as a rate reduction through the SNA deferral. We examined PGE's marketing efforts to determine whether changes occurred that are consistent with these theories.

Table 6.4.1 shows the allocation of PGE's advertising expenses from 2006 through 2012. Across the categories, the only statistically significant trend is the increase in the expenses related conservation programs. This is likely due to the increase in available funds enabled by SB 838.

Since 2006, total annual advertising expenses across all categories peaked in 2010 and dropped significantly in 2011 and 2012 to their lowest levels. That is, conservation promotion does not appear to have added to advertising expenditures, but instead supplanted marketing activities that may have otherwise been included in the other two categories.

Table 6.4.1: Category Shares of PGE Advertising Expenses

Year	Shares of Advertising Expenditures:		
	Image/Brand	Information & Retail Delivery	Conservation
2006	31%	69%	0%
2007	26%	74%	0%
2008	30%	65%	5%
2009	31%	59%	10%
2010	36%	54%	11%
2011	5%	79%	16%
2012	20%	61%	20%

A review of print and online newsletters mailed to customers directly or included as bill inserts revealed few discernible changes in content that may be associated with decoupling. Prior to implementing Schedule 123, PGE often included energy efficiency and conservation items in its customer materials, and that did not change after 2009. We paid particular attention to messaging directed at residential customers through a two-page monthly bill insert, titled "Update." A simple count of items related to energy savings, as classified in annual editorial calendars, reveals that the number of items increased from an average of 22 stories per year before and including 2009 to 26 stories thereafter. Relative to items related to corporate citizenship, which could be considered analogous to image advertising, stories about energy saving initiatives appeared more often and with a larger share of stories after 2009 (omitting the anomalous 2007 counts).

Table 6.4.2: Count of References to Energy Savings and Corporate Citizenship in Residential Customer Newsletter (Update, 2006-2012)

Year	Number Items in Update Addressing "How does PGE…"		Ratio (Energy Savings/Corporate Citizenship)
	"… Help me save energy?"	"…Make my community better for me and my family?"	
2006	21	20	1.1
2007	26	7	3.7
2008	21	15	1.4
2009	21	21	1.0
2010	26	20	1.3
2011	25	21	1.2
2012	27	18	1.5

In our review of the residential bill inserts, we also investigated whether there were any load growth programs that PGE stopped promoting after the implementation of the SNA. That is, the SNA removes both PGE's disincentive to promote conservation and its incentive to promote load growth (in terms of use per customer). The only potentially relevant finding from this investigation was that PGE appeared to cease promotion of its outdoor area lighting program in October 2008. While this type of service is safety related, it could also be considered a load growth initiative, in that it represents a new end use for existing customers. However, PGE informed us that this change was unrelated to the SNA and that it intends to promote this type of lighting again in the future.

6.5 Customer Satisfaction

PGE monitors customer satisfaction through annual and quarterly reports from three market research firms. In this section, we summarize customer satisfaction survey results from J.D. Power and Associates (JDP), Market Strategies International (MSI), and TQS Research, Inc. (TQS).

JDP produces annual reports of customer satisfaction in the electric utility industry, with separate reports for business and residential customers. Along with the executive summary, which summarizes results for the entire industry, PGE also receives PGE-specific details regarding components of customer satisfaction and indicating PGE's rank within the West Region and across the industry.[54]

[54] For business customer reports prior to 2010, JDP ranked PGE relative to all utilities serving greater than 25,000 business customers in the West Region. Beginning In 2010, JDP further split utilities by size segment, where midsize utilities are defined as those having between 25,000 and 85,000 business customers and large utilities have greater than 85,000 business customers. A similar modification was made in 2008 with respect to residential utility rankings. Beginning in 2008, residential utilities within each region are split into large (500,000 or more

PGE provided annual JDP customer satisfaction results from 2006 through 2012. Because this information is confidential, we will only describe results in terms of PGE's rank within its peer group (large utilities in the West Region) or PGE's score relative to the average score in that group (benchmark). The following categories are of particular interest:

- Overall Customer Satisfaction Index[55]
- Power Quality & Reliability
- Price
- Customer Service
- Awareness of Energy Efficiency and Conservation Programs[56]

Tables 6.5.1 and 6.5.2 list PGE's rank within the West Region from 2006 to 2012 for business and residential customers, respectively. For both customer groups, PGE has ranked in the top half of the West Large Segment since 2009 in all categories with only one exception. In 2011, PGE ranked 7th out of 13 utilities with residential customers in the Price category, which is consistently PGE's weakest area for both customer groups.

Table 6.5.1: PGE's Rank among Large West Region Utilities, *Business*

Year	Overall CSI	Power Quality & Reliability	Price	Customer Service
2006	9 of 12	5 of 12	8 of 12	2 of 12
2007	5 of 12	3 of 12	7 of 12	5 of 12
2008	5 of 13	2 of 13	7 of 13	1 of 13
2009	1 of 19	1 of 19	5 of 19	2 of 19
2010	2 of 12	1 of 12	4 of 12	4 of 12
2011	2 of 12	2 of 12	2 of 12	2 of 12
2012	2 of 12	2 of 12	3 of 12	2 of 12

residential customers) and midsize (125,000 to 499,999 residential customers) categories. PGE is considered a large utility with respect to both residential and business customers.

[55] The Overall CSI is a weighted composite of satisfaction results in six categories: Billing & Payment, Price, Power Quality & Reliability, Communications, Customer Service, and Corporate Citizenship.

[56] This measure was reported beginning in 2008 for residential customers and 2009 for business customers.

Table 6.5.2: PGE's Rank among Large West Region Utilities, *Residential*

Year	Overall CSI	Power Quality & Reliability	Price	Customer Service
2006	6 of 12	4 of 12	10 of 12	3 of 12
2007	3 of 13	2 of 13	4 of 13	1 of 13
2008	3 of 13	2 of 13	5 of 13	2 of 13
2009	3 of 13	3 of 13	5 of 13	1 of 13
2010	3 of 13	2 of 13	4 of 13	2 of 13
2011	3 of 13	2 of 13	7 of 13	4 of 13
2012	3 of 13	2 of 13	5 of 13	2 of 13

Figures 6.5.1 and 6.5.2 show how PGE's score in each category (relative to the average large West Region utility, expressed as a ratio) evolved from 2006 to 2012 for business and residential customers, respectively. With respect to business customers, the trend in each category is upward sloping suggesting that PGE has improved customer satisfaction relative to its peers. Residential customer satisfaction appears to have peaked in 2007 and has remained relatively flat between 2008 and 2012.[57] For both customer groups, almost every data point from 2008 forward is greater than one, indicating cases where PGE outperforms its benchmark.

[57] Residential satisfaction with customer service has declined consistently since 2007 relative to the average large West region utility. This is due primarily to increases in satisfaction for the benchmark utility rather than a decline in PGE's customer service.

Figure 6.5.1: PGE Satisfaction Scores Relative to Average, *Business*

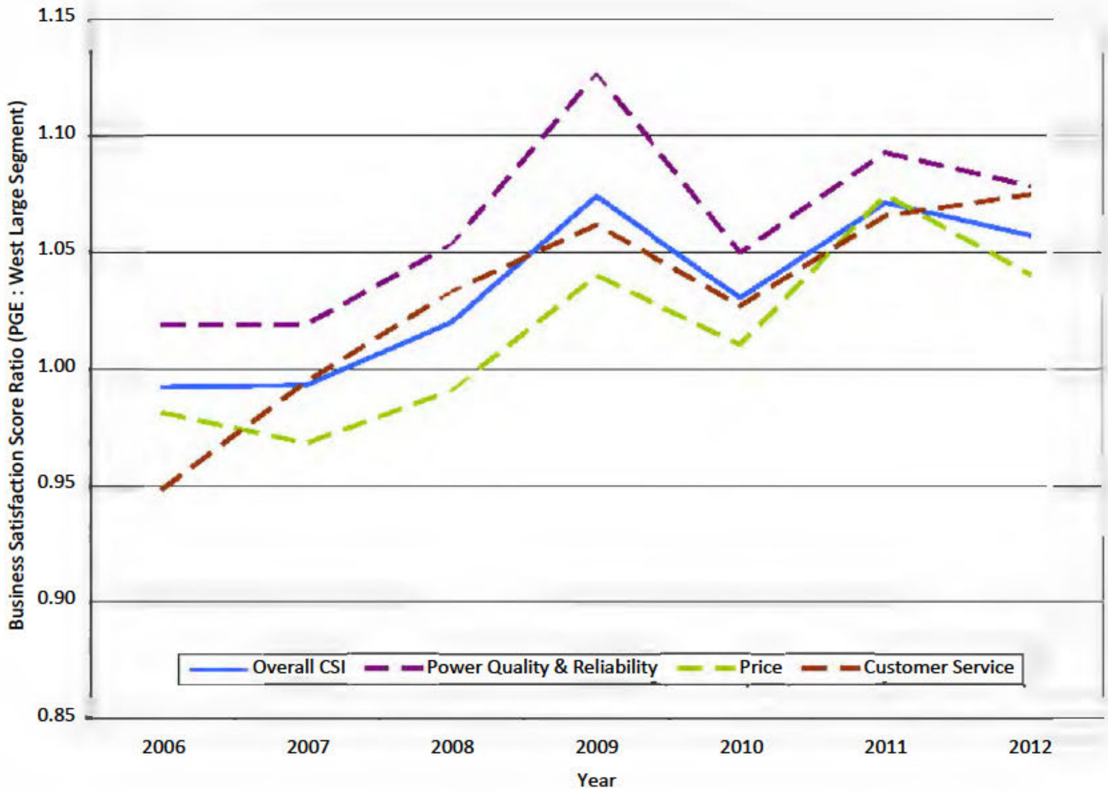
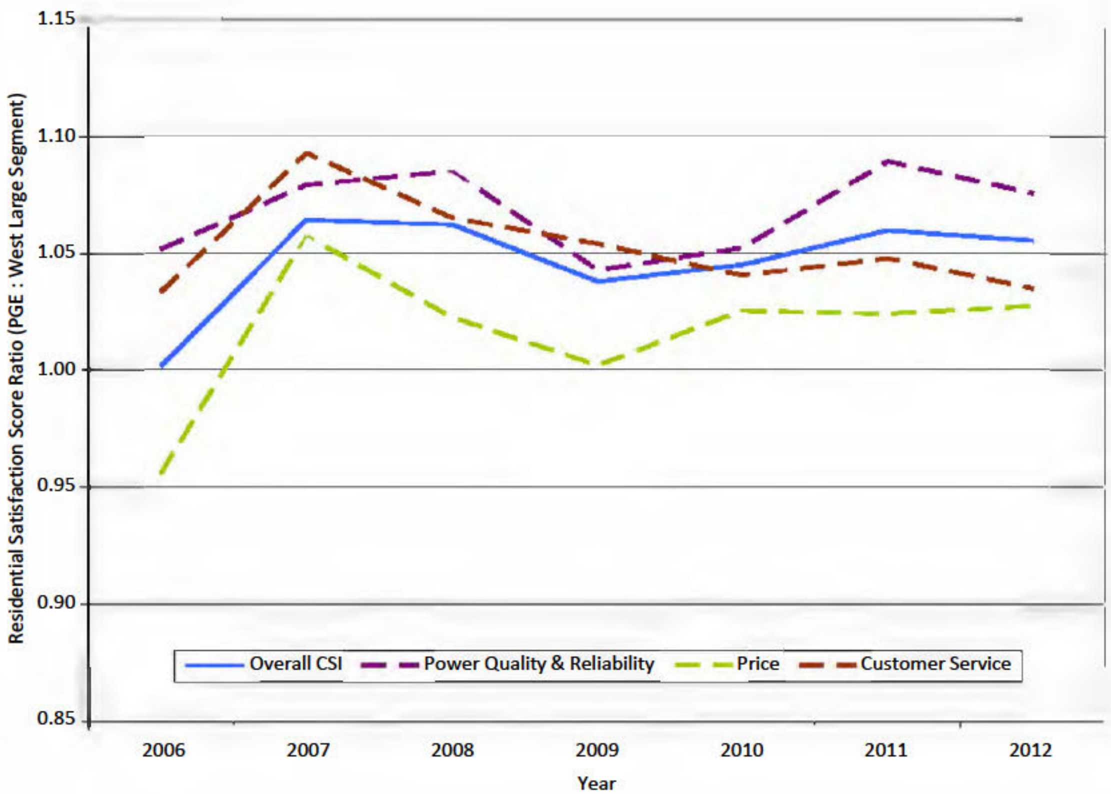
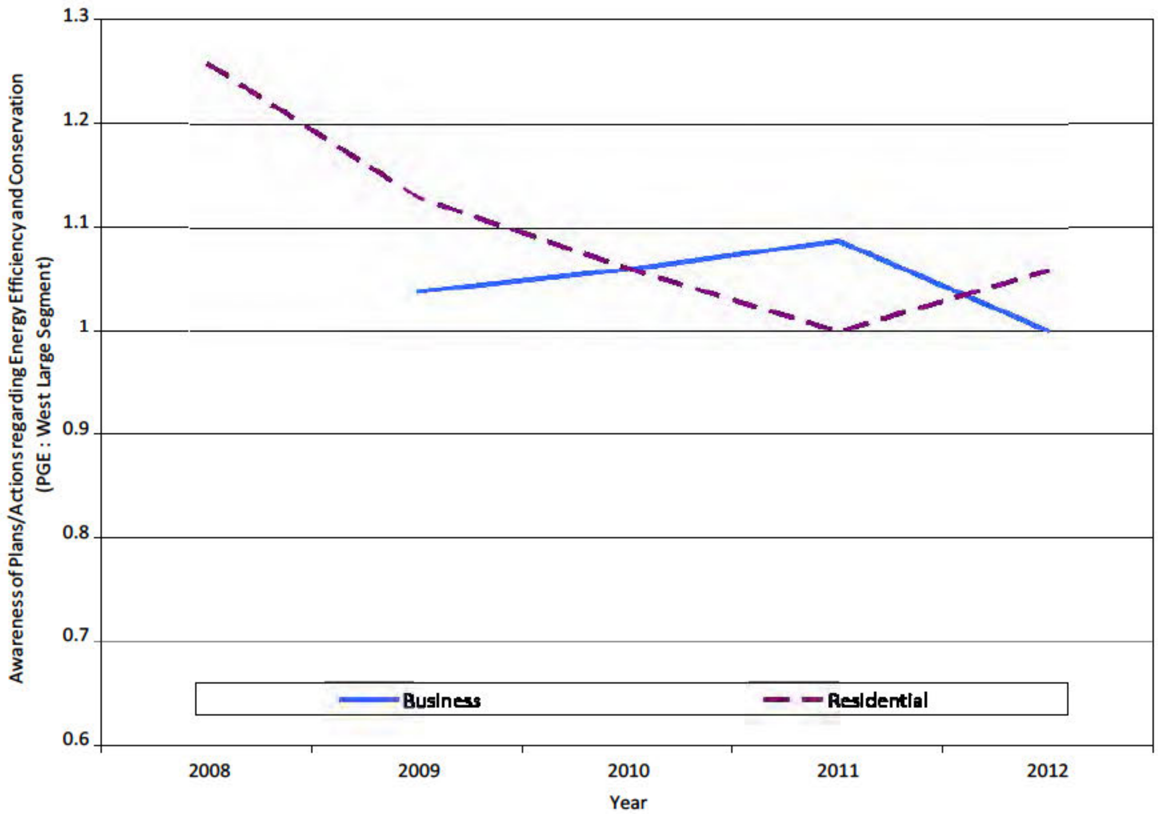


Figure 6.5.2: PGE Satisfaction Scores Relative to Average, *Residential*



In 2008 and 2009 JDP began tracking customer awareness of utility actions with respect to energy efficiency programs and conservation. Figure 6.5.3 provides awareness statistics as a ratio of the share of aware customers at PGE relative to the average large West Region utility. For both customer groups, the ratios are always greater than or equal to one, indicating that PGE's awareness is consistently on par or better than that for comparable utilities. The figure shows a decline in awareness for residential customers and stable awareness for business customers. For the residential customers, the decline can be attributed to both a decrease in awareness for PGE customers and in increase in awareness for the benchmark utilities.

Figure 6.5.3: PGE Customer Awareness of EE and Conservation Relative to Average



Like JDP, MSI conducts surveys for business and residential customers separately. Each survey has a sample of approximately 400 customers and results are reported quarterly (every other quarter for business customers) from 2006 to 2012.[58] MSI asks customers to score their utility on a scale from 1 to 10 on a variety of topics. MSI then summarizes results for each question in terms of the percent of customers who "agree" or give "positive" responses (scores between 6 and 10). The following four measures of residential and business customer satisfaction are summarized in Figures 6.5.4 and 6.5.5:

- Overall Satisfaction
- Overall Favorability
- Showing Concern and Caring (towards customers)
- Value of Customer Service

Because MSI data are confidential, Figures 6.5.4 and 6.5.5 show PGE's scores relative to the average score for utilities in the PGE peer group (expressed as a ratio).[59] Again, in every case

[58] Only results from 4th quarter reports are summarized here.

[59] MSI defines the peer group to include eight or nine large western utilities. The peer group consists of varying combinations of the following utilities in each year: Pacific Gas & Electric, Pacific Power, Puget Sound Energy, Rocky Mountain Power, Southern California Edison Company, Seattle City Light, San Diego Gas & Electric, Sierra Pacific Power Company, NV Energy North, and NV Energy South.

the value of each ratio is above one indicating above average performance from PGE. With respect to business customers, each measure was stable or declining through 2009 but recovered in 2010. Overall satisfaction and overall favorability maintained or exceeded 2010 levels into 2012; however the two remaining factors related to customer service declined in both 2011 and 2012. With respect to residential customers, all four measures of satisfaction declined from 2008 to 2011 and saw large rebounds in 2012.

Figure 6.5.4: PGE Satisfaction Scores Relative to MSI Peer Group, *Business*

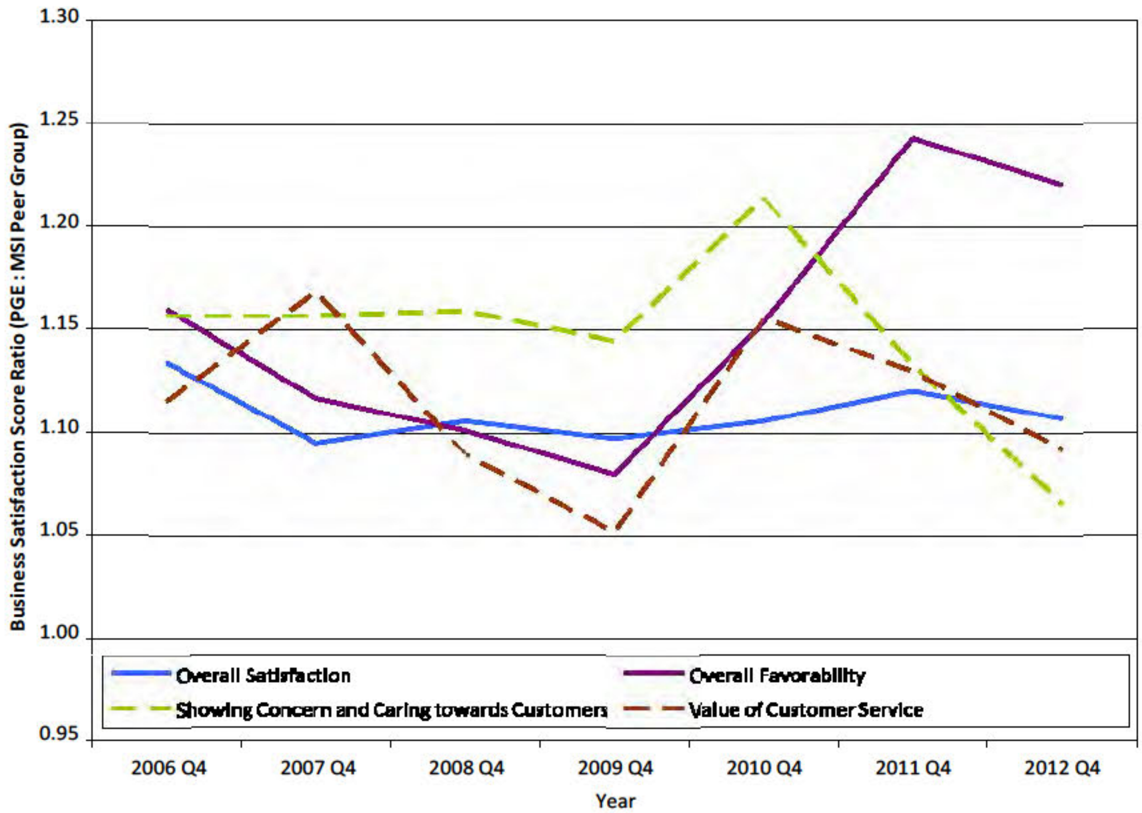
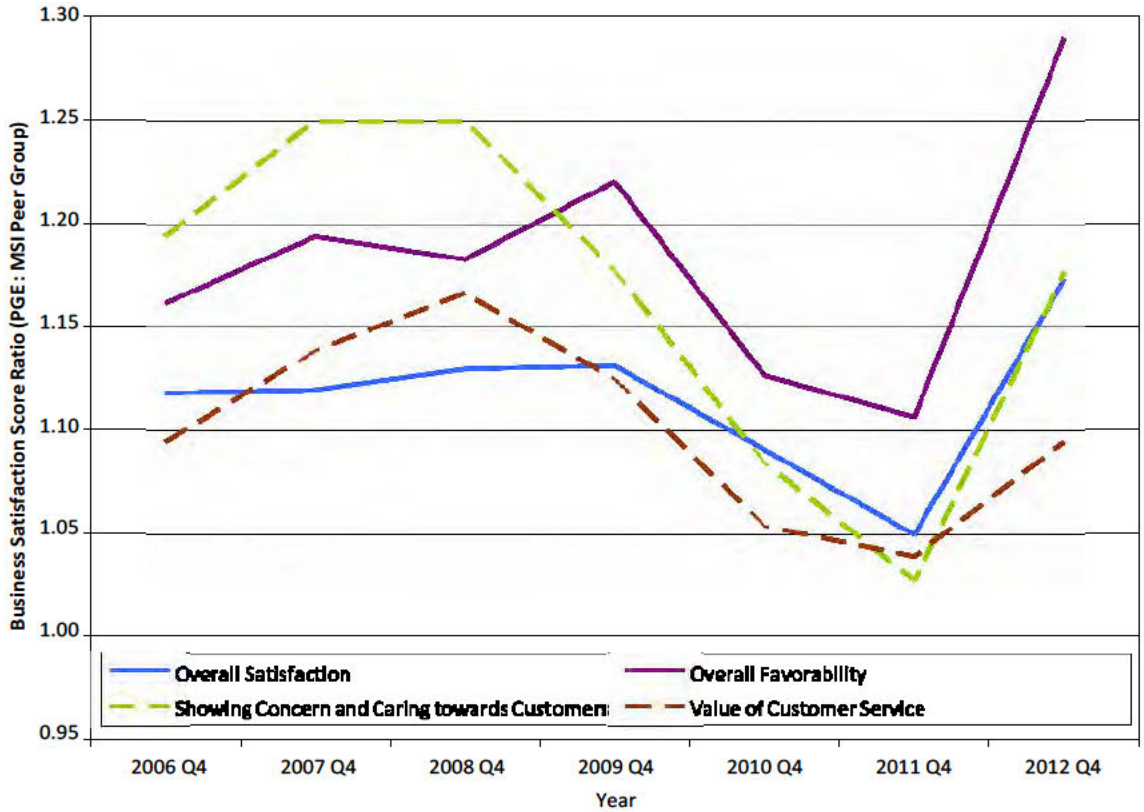


Figure 6.5.5: PGE Satisfaction Scores Relative to MSI Peer Group, *Residential*



MSI also reports the percentage of customers who agree (scores between 6 and 10) that PGE "offers practical advice on how to save money on your electric bills," but does not provide a benchmark value from the peer group. Greater than 80 percent of customers agree with this statement in all years and in both customer groups. The scores are relatively stable, with a six percentage point spread between highest and lowest score for business customers and only a four percentage point spread for residential.

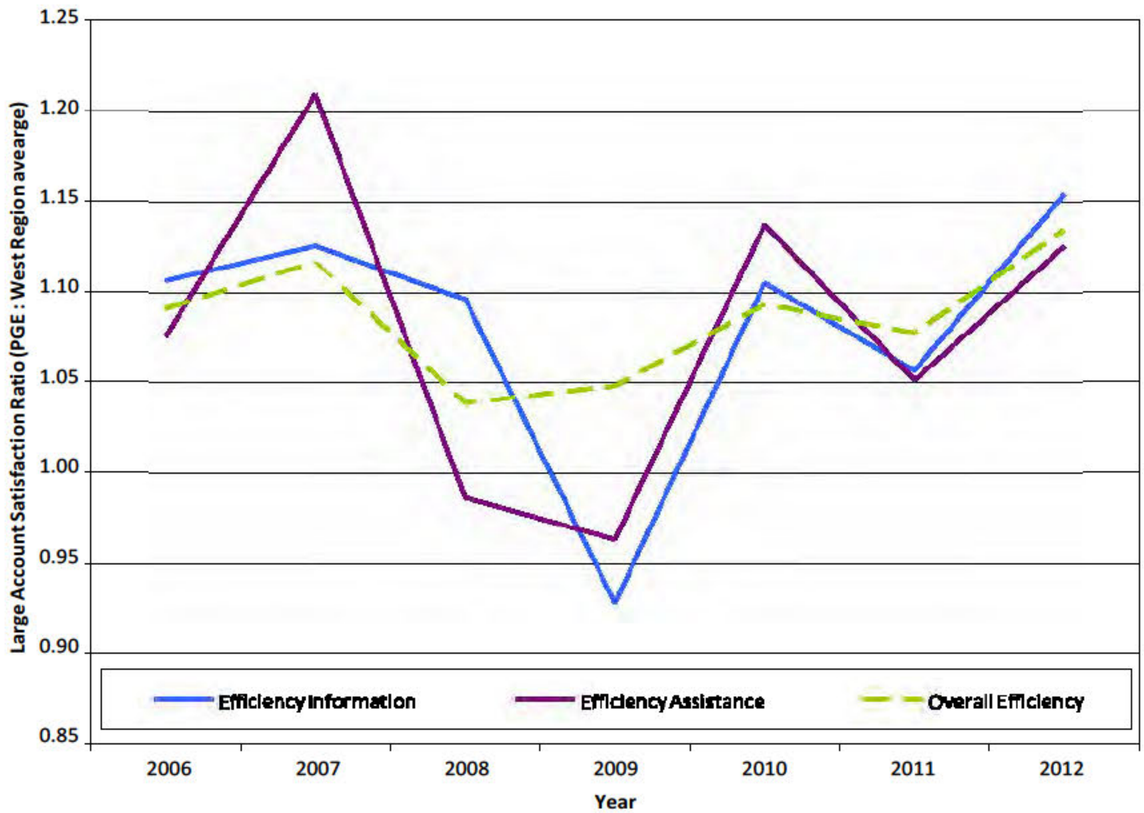
Finally, TQS conducts interviews and generates annual reports summarizing satisfaction of large accounts for PGE and an additional 65 or more large utilities.[60] TQS asks survey respondents to rate PGE from 1 to 10 (10 being "very satisfied") on several topics, in particular:

- Providing you with information to make energy efficiency decisions;
- Providing technical assistance to make your company more energy efficient; and
- Overall satisfaction with your utility's efforts to make your company energy efficient.

[60] TQS defines large accounts to be "manufacturing facilities with a demand of over 1,000 kW, plus large hospitals & universities." As many as 100 utilities are included in the 2012 TQS report and as few as 65 in 2006. Note that many of these customers may not be eligible for Schedule 123, which does not apply to customers with usage exceeding 1 aMW.

TQS summarizes responses based on the percentage of customers who are "very satisfied" (those who give scores between 8 and 10). Figure 6.5.6 summarizes PGE's share of very satisfied customers relative to that of the West Region average (expressed as a ratio) from 2006 to 2012 for each of the three energy efficiency topics. All three measures saw lower scores in 2008 and 2009 and rebounded in following years. With the exception of one data point (efficiency information in 2009), all ratios are greater than one indicating above average performance from PGE.

Figure 6.5.6: Large Account Satisfaction with Energy Efficiency Programs Relative to West Region Average



6.6 Customer Complaints

We asked OPUC Staff to provide us with customer complaints that can be attributed to Schedule 123. Their response consisted of three complaints. The first, from March 2009, contained a fairly common (in our experience) objection to decoupling on the grounds that customers "pay for energy that they did not use." We do not find this objection to be compelling, because decoupling relates only to fixed costs, not variable energy costs. Therefore, even under decoupling, customers will pay for less energy if they use less energy.

The second complaint, from April 2009, objected to decoupling based on a belief that the utility should not be able to apply a surcharge to rates when customers use less. The customer believed that it was unethical for PGE to propose such a charge with their history of financial waste, and urges the Commission to consider the history of decoupling in the Northeast United States.[61] The overall message of the complaint appears to relate to concerns about a shift in economic risk from PGE to its ratepayers. Our analysis in Section 4 indicates that this concern is not without merit, though the overall improvement in economic conditions during the period in which the SNA has been in effect has caused the SNA to benefit customers at the expense of PGE.

The third case record (from August 2011) was more of an inquiry than a complaint. The customer was confused by the fact that the SNA credit had changed to a charge across billing periods. The customer's question was answered and the case was closed.

6.7 Service Outages

In a December 2012 stakeholder meeting, a question regarding service quality was added to the evaluation requirements. Specifically, it reads "Did the partial decoupling mechanism affect, positively or negatively, levels of service quality or the company's incentives to provide excellent service quality."[62]

From an incentive perspective, the mechanics of the SNA suggest that PGE could face a reduced incentive to resolve service outages. That is, under the SNA, PGE recovers fixed costs based on the number of customers served rather than on the sales to those customers. Therefore, the revenue associated with a reduction in sales that occurs because of a widespread outage would be recovered through the SNA deferral.

Realistically, we do not expect that the change in the financial incentive is large enough to affect PGE's behavior with respect to resolving outages. Even with the revenue assurance provided by the SNA, the cost savings the utility could achieve by allocating fewer resources to resolving outages seem small when compared to the safety issues, costs associated with dealing with an increase in customer complaints, and the adverse affects associated with a decrease in customer satisfaction that would likely result from allowing longer service outages.

Table 6.7.1 summarizes PGE's service outages from 1999 through 2011. The data are taken from PGE's 2011 Service Quality Measure Report. The rows containing 2009 through 2011 are italicized to indicate the years in which Schedule 123 was in place. Comparing the three years before and after Schedule 123 was implemented (as shown in the means at the bottom of the table), we find improvements in SAIDI, SAIFI, MAIFI, and the number of outages. CAIDI is the only measure that is worse when Schedule 123 was in effect.

Based on these data, we do not see any evidence that PGE's service quality was adversely affected by the introduction of Schedule 123.

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[61] The customer is likely referring to the introduction and subsequent withdrawal of a decoupling mechanism for Central Maine Power.

[62] If one prefers to interpret "service quality" to mean customer service rather than addressing service outages, then this question is addressed in Section 6.5 (customer satisfaction).

Table 6.7.1: PGE Service Outage Data, *1999 – 2011*[63]

Year	SAIDI (minutes)	SAIFI (#/Customer)	MAIFI (#/Customer)	CAIDI (minutes)	# Outages
1999	83	0.78	3.30	106.4	4,216
2000	64	0.62	2.70	103.2	4,040
2001	67	0.65	2.20	103.1	4,558
2002	73	0.65	2.20	112.3	4,935
2003	82	0.80	2.10	102.5	5,366
2004	85	0.80	1.80	106.3	5,582
2005	86	0.83	1.60	103.6	5,560
2006	117	1.06	1.60	110.4	6,930
2007	77	0.71	1.30	108.5	5,994
2008	75	0.73	1.30	102.7	5,817
2009	*115*	*0.81*	*1.40*	*141.6*	*6,354*
2010	*77*	*0.65*	*1.10*	*118.3*	*5,454*
2011	*66*	*0.51*	*0.89*	*129.0*	*4,535*
Averages:					
w/ Schedule 123 (2009-11)	**86.0**	**0.66**	**1.13**	**129.6**	**5,448**
3 yrs. Prior (2006-08)	**89.7**	**0.83**	**1.40**	**107.2**	**6,247**
All prior years (1999-2008)	**80.9**	**0.76**	**2.01**	**105.9**	**5,300**

7. STAKEHOLDER INTERVIEWS

We contacted the key stakeholders (which include CUB, ETO, Kroger, Northwest Energy Coalition, OPUC Staff, and PGE) to provide them with the opportunity to provide feedback on the SNA and LRRA. PGE's feedback consisted of the responses to our data requests. We had some communication with OPUC Staff to discuss the project and desired areas of inquiry. Finally, we had detailed conservations with the ETO and Kroger, which are summarized in the following sub-sections. We did not receive responses from CUB or the Northwest Energy Coalition.

7.1 Energy Trust of Oregon

We spoke with Margie Harris, who is the Executive Director of the ETO. As the third-party provider of conservation and energy efficiency programs, the ETO has a unique perspective on the effects of Schedule 123. In our conversation, Ms. Harris was weakly supportive of Schedule 123. That is, she said that it helps make PGE neutral to the effects of conservation, but does not provide them with a direct incentive to advocate conservation. In addition, she believes that several other factors, such as funding provided under Senate Bill 838 and the least-cost planning required of PGE's Integrated Resource Plans, are more significant drivers of PGE's behavior with respect to conservation than Schedule 123. Ms. Harris did not believe that she

[63] SAIDI is the System Average Interruption Duration Index; SAIFI is the System Average Interruption Frequency Index; MAIFI is the Momentary Average Interruption Frequency Index; and CAIDI is the Customer Average Interruption Duration Index.

was in a position to determine the extent to which the adoption of Schedule 123 affected PGE's behavior, independent of these other factors.

However, she also stated that ETO's research indicates that utility cooperation in the promotion of conservation and energy efficiency programs improves program performance. That is, program performance is improved when PGE and the ETO work together (e.g., through joint messaging) rather than separately. This suggests a valuable role for PGE in promoting ETO's programs. She indicated that PGE has been very committed to working with the ETO.

The ETO provides conservation and energy efficiency programs for all customer classes. PGE has three different types of customers, from a conservation incentive perspective:

1. Those covered by the SNA (residential and small commercial);
2. Those covered by the LRRA (medium commercial and industrial); and
3. Those with no mechanism for the recovery of lost revenues.

We asked Ms. Harris whether she has observed any differences in PGE's efforts to work with ETO across these groups. She responded that she has not, though she suspects that in the future, the ETO will attempt to obtain an increasing share of its energy savings from the "group 3" customers. She believes that this may provide a test of PGE's willingness to promote conservation in the absence of any regulatory mitigation of lost revenues.

OPUC Staff conveyed to us additional information they received from Kim Crossman of the ETO. The specific feedback we received from Staff follows:

> [I]n conversation with Kim Crossman of the ETO, Staff has identified that PGE, in their function as a Program Delivery Contractor (PDC) for the ETO, aggressively targets smaller customers relative to other PDC contractors. This evidence suggests that the LRRA provides a conflict of interest for PGE. As a PDC, the Company should promote energy efficiency based on cost effectiveness. However, because the LRRA only decouples customers under one MWa, PGE has the incentive and opportunity to shift Senate Bill 1149 and Senate Bill 838 funding from large customers to small customers.

While the above information does not fully align with the feedback we received from Ms. Harris, we believe that it may provide the strongest evidence we have found thus far that PGE responds to the disincentive to promote conservation that is inherent in its rates, without Schedule 123. Above, Staff expresses the view that PGE "should promote energy efficiency based on cost effectiveness." However, this obligation exists in the absence of Schedule 123, and despite this the Commission ruled that "a properly constructed decoupling mechanism would promote behavior by the Company that would be publicly beneficial."[64]

[64] Order No. 09-020, page 28.

If the information provided by the ETO indicates that PGE is diverting its promotions of energy efficiency away from classes unaffected by Schedule 123, we suggest that a potential remedy is to expand the eligibility of the LRRA rather than remove it entirely.

7.2 Kroger

Denis George and Kevin Higgins provided us with feedback regarding Kroger's view of Schedule 123. The main points they expressed can be summarized as follows:

- Kroger believes that the utility disincentive to promote conservation and energy efficiency is overstated as a general matter. In Oregon, the presence of the ETO as a third-party provider of conservation and energy efficiency programs further reduces the effect of the incentive issue in Kroger's view.
- Kroger opposes the SNA because they believe it transfers risk from PGE to its customers.
- The LRRA is less objectionable to Kroger than the SNA because it is limited to the effects of energy efficiency measures. However, Kroger opposes the LRRA as well. If the LRRA is retained, Kroger would like it to be modified to address the following perceived flaws (quotation marks are used to indicate statements provided directly from Kroger):
    - The LRRA "provides for adjustments to the rates paid by Direct Access customers that include recovery of PGE's fixed generation revenues that are alleged to be lost as a result of energy efficiency measures. PGE's fixed generation costs should be excluded from any LRRA rates applicable to Direct Access customers that are participating in multi-year opt-outs."
    - "The LRRA is asymmetrical in that it does not take account of 'found revenues' that could accrue to PGE as a consequence of new load. Specifically, the LRRA focuses on the sales impact of energy efficiency measures in isolation and neglects to consider the effects of overall load growth on fixed cost recovery. In practice, the implementation of energy efficiency programs does not imply that a utility will be unable to fully recover its fixed costs. In general, when load grows above the level of the billing determinants used in setting rates, the fixed-cost recovery that occurs as a function of volumetric sales increases. This inures to the benefit of the utility. In traditional ratemaking, utilities are <u>not</u> required to return this incremental fixed-cost recovery to customers. This incremental fixed-cost recovery can be thought of as 'found' margins. If a 'lost margins' approach is adopted, then 'lost margins' should be netted against 'found margins.' Specifically, the kilowatt-hours used for measuring going-forward lost revenue recovery should be limited to the <u>lesser</u> of energy efficiency improvements attributable to energy efficiency measures or actual net reductions in retail kilowatt-hours sold relative to the retail kilowatt-hours used in setting base rates."
- Kroger believes "that 'lost' fixed cost recovery attributable to energy efficiency measures can be mitigated through rate design for demand-billed customers. For example, Arizona Public Service Company ('APS') negotiated a Lost Fixed Recovery Mechanism ('LFCR') with stakeholders as part of its last general rate case. APS's LFCR is similar to the LRRA, except that it excludes customers with billing demands greater than 400 kW because the lost revenue concerns for these customers are addressed by

aligning demand-related costs with demand charges, which are typically a more stable source of revenue than energy charges."

- Denis George pointed out that Kroger is self-motivated to conserve. There is a general frustration that they are required to participate in energy efficiency funding mechanisms and programs that they would likely pursue without the costs associated with regulatory intervention. He stated his belief that it is more difficult to make the case for energy efficiency projects in the presence of decoupling (and presumably the LRRA).

8. AREAS OF POTENTIAL HARM NOT INVESTIGATED IN THE STUDY

After reviewing a draft of this study, OPUC Staff requested that we "[i]dentify potential sources of harm from the decoupling mechanisms that were not fully investigated in the Report." Staff provided the example that "the social cost due to the shift in economic risk from the Company to the customer was not identified," including and investigation of "whether the Company, investors in the company, or the individual customer is best able to deal with the risk."

Addressing Staff's specific suggestion first, we do not see a straightforward means of identifying which party is best positioned to deal with economic risk, though we provide some thoughts on the matter.

First, the shift in economic risk does not seem large. Assuming that the SNA covers approximately 50 percent of Schedule 7 revenue, even the recent severe decline in economic conditions would have only produced approximately a 0.9 percent increase in customer bills. For Schedule 32 customers, the SNA-induced bill increase may have approached the 2 percent rate adjustment cap (these figures are based on results presented in Table 4.4.4).

Second, the economic risk shift is not distributed equally across customers within a rate class. That is, it seems likely that in comparatively dire economic circumstances, some customers are forced to dramatically reduce their usage while others do not need to make any adjustment at all. Extending the "peak-to-trough" example from above, a particular customer who reduced usage by 10 percent in response to a reduction in income would receive an SNA-rate increase in the following year based on the smaller 1.8 percent decrease in UPC that occurred for the entire class. Therefore, while the risk is shifted from the Company to the *class* of customers, the effect on *individual* customers varies.

Regarding the various parties' ability bear risk, the issue seems quite complex. Looking only within the residential customer class, there are a range of entities: low-income customers who could experience harm from even relatively small rate increases; and comparatively well-off customers for whom the electric bill is small part of their overall finances. Utility investors may also include a wide range of parties, including small individual investors, pension funds, or large institutional investors. The utility itself may have tools to mitigate cash flow risks (e.g., through a line of credit or cash reserves) or mitigate longer-term recovery issues (e.g., by filing a rate case). However, PGE is not very diversified in its operations, such that deterioration in its electricity sales can have a significant effect on its overall financial health. Devising a means of evaluating the ability these parties to bear risk is not within the scope of this study.

Given the thorough list of evaluation requirements, we do not believe there are many other areas of potential harm from Schedule 123 that have remained uninvestigated. We can only think of one area at this time: the distributional effects of SNA deferrals. That is, consider an example in which half of the customers reduce usage by 4 percent by pursuing conservation and energy efficiency, while the remaining half takes no action at all. Suppose that the net effect of this is a 1 percent bill increase through the SNA deferral mechanism (under the assumption that 50 percent of the total bill is covered by the SNA). The conserving customers in this example experience a net reduction in their bill, but some of the fixed cost recovery has been shifted from these customers to the non-conserving customers.

We have not investigated the effect of these potential intra-class allocation/subsidy issues. One can imagine a circumstance in which wealthier customers are more able to engage in conservation than low-income customers, with the result being an SNA-induced shift in cost recovery from high- to low-income customers. While we have not explored the existence or size of such an effect, we note that an alternative to decoupling in which all fixed costs are recovered through fixed charges (SFV pricing, described in footnote 67) has much more potential to shift cost recovery to low-income customers.

9. CONCLUSIONS AND RECOMMENDATIONS

Summary of the Study

In this study, we evaluated the Sales Normalization Adjustment and Lost Revenue Recovery Adjustment mechanisms approved for use by PGE in 2009 as Schedule 123. A primary motivation for implementing these mechanisms is to remove the disincentive to promote conservation and energy efficiency that PGE faces because fixed costs are recovered, at least in part, through volumetric rates.

The study consists of an examination of each mechanism to determine whether it functions as intended; an evaluation of whether PGE’s behavior changed in a manner consistent with a change in its incentives to promote conservation and energy efficiency; an evaluation of whether Schedule 123 reduced PGE’s risk; development of a statistical model to determine whether changes in use per customer (which affect SNA deferrals) are related to changes in economic conditions or energy prices; and an examination of PGE customer satisfaction and service quality to determine whether either suffered under Schedule 123.

A summary of findings follows:

1. The design of the SNA is effective in eliminating PGE's disincentive to promote conservation and energy efficiency to residential (Schedule 7) and small commercial (Schedule 32) customers.
2. The design of the LRRA is effective in reducing PGE's disincentive to support the ETO's conservation programs for the applicable rate schedules. (However, some disincentive may continue exist if PGE expects a mismatch between actual and estimated conservation from ETO programs.)
3. We do not find compelling evidence that the change in incentives led to significant changes in PGE's corporate behavior, though some actions were reported.
    a. PGE reports no change to its labor compensation practices and policies.
    b. PGE hired several employees to provide customer outreach regarding conservation programs.
    c. PGE introduced the Energy Tracker, which is an on-line tool that helps customers identify opportunities to conserve.
    d. PGE did not appear to alter its retail rate structures because of the incentive effects of Schedule 123 (this is understandable given that the SNA does not cover weather effects on sales and revenues).
    e. The ETO reports that PGE has been a valuable and effective partner in promoting its programs, but it is difficult for them to attribute this behavior to Schedule 123. The ETO cited other factors, such as funding provided under SB 838 or least-cost planning required by the Integrated Resource Plan as likely drivers of PGE's behavior.
    f. It is difficult to identify a change in PGE's marketing activities that was directly in response to the introduction of Schedule 123.
    g. Neither PGE's service quality nor its customer satisfaction appears to have been adversely affected by Schedule 123.
4. Based on our own empirical study, a review of other studies, and information provided in credit agency ratings reports, we do not find any evidence that the introduction of Schedule 123 reduced PGE's capital risks by a material amount. We therefore do not find a justification for adjusting PGE's allowed return on equity because of Schedule 123.
5. Our statistical analysis indicates that some economic risk may be shifted from PGE to its Schedule 7 and 32 customers.[65] The experience to date indicates that this has benefitted those customers, as economic conditions have improved since early 2009. The same analysis indicates that the SNA does *not* shift price risk to customers (i.e., there is no statistically significant relationship between the real electricity price and use per customer).

[65] This is not necessarily inconsistent with the finding that Schedule 123 did not materially reduce PGE's overall risk, as the amount of economic risk may be small in comparison to the combination of all of the other risks to which PGE is exposed.

Recommendations
For our recommendations, we provide answers to two required analysis questions that were not addressed in the body of the report.

11. How often should the fixed costs and use-per-customer parameters be updated?
Our findings do not provide a conclusive answer to this question. Our view is that there is no need to deviate from status quo, in which the mechanisms are updated as a part of rate cases initiated in the usual way (which is typically for the utility to file of its own accord, but the Commission also has the authority to compel the utility to undergo a rate case). The deviations that the SNA and LRRA cause relative to the outcomes that would have occurred under standard rates seem likely to be small enough such there is no need to require the utility to file more frequently than it otherwise would have. That said, if the stakeholders would be more comfortable with the long-term effects of Schedule 123 if the Commission were to impose something like a maximum five-year rate case window (i.e., there can be no more than five years in between PGE rate cases while Schedule 123 is in effect), the only harm that would be incurred would be the costs associated with the ratemaking process.

12. What would you recommend as improvements to the current PGE decoupling mechanism? Should it continue beyond 2013? Should it be terminated? Should it be modified? If so, what specific modifications should be made?
As described in the summary of our findings above, our evaluation has provided no overwhelmingly compelling reason to support the continuation or termination of Schedule 123. Little harm seems to have been incurred at this point: customer satisfaction and service quality are fine; total deferrals to date have been relatively small (a total net effect of approximately $500,000 across 2009-2012); and the ETO is generally pleased with the effort that PGE is giving in support of its programs.

Still, it is difficult to find evidence that Schedule 123 has caused PGE to behave differently than it would have in the absence of the mechanisms. However, some pro-conservation behaviors have been observed, including the introduction of the Energy Tracker; the hiring of additional staff to increase awareness of conservation and energy efficiency programs; and continued support for the ETO. We are not in a position to know whether these actions would have occurred in the absence of Schedule 123.

Taking all of this into consideration, we recommend the continuation of Schedule 123. While the evidence is not conclusive, we are swayed by the presence of some good (e.g., the ETO reporting that PGE is a good partner in promoting its programs) and very little evidence of harm. Since the ETO’s conservation goals are no less ambitious in the future, it would be beneficial to ensure PGE’s cooperation going forward.

We suggest some modifications to each mechanism, as follows.

For the LRRA:

- Remove the generation component from the charge paid by Schedules 485 and 489. There is no lost revenue toward generation costs for these customers, because it is not part of their standard rates.
- If it is administratively feasible, use schedule-specific Lost Revenue Rates, with the total ETO conservation spread across rate schedules in proportion to test-year sales levels. This method seems like a feasible method of reducing (but not eliminating) cross-subsidies due to LRRA adjustments without being unduly burdensome administratively.

For the SNA:

- Consider removing the weather normalization of “actual” sales (and therefore revenues) from the calculation. This has the following potential benefits.
    - o It would enable PGE to implement rate structures that may provide customers with higher incentives to conserve, such as lower customer charges (and higher volumetric rates) or more steeply inclining block rates. Under the current SNA, these rate structures would be unappealing to PGE because of the weather-induced variability in revenues toward fixed costs that they could produce.[66]
    - o It would allow for the reduction of weather risk for both PGE and its ratepayers. Some progress would be made in this regard by simply removing the weather adjustment to sales. However, it would be an even more effective risk mitigating measure if the SNA design change was accompanied by the introduction of a monthly weather adjustment. This would allow the weather risk mitigation to benefit customers in the current month rather than waiting for the effects of the modified SNA deferrals.[67] We acknowledge that the administrative cost associated with introducing the separate weather adjustment may more than offset the benefits of the additional risk mitigation that it would provide.
- Consider a bifurcation of the SNA so that separate calculations are conducted for the generation and transmission cost components (with the remaining cost components

[66] Note that the proposed changes to rate structure tend to go against marginal-cost-based pricing principles, in which fixed costs are recovered with fixed charges and variable costs are recovered with unit rates that closely approximate the unit costs. Such pricing, called Straight Fixed Variable (“SFV”) pricing in natural gas (in which all fixed costs are recovered through the monthly customer charge), is another effective means of removing the utility’s disincentive to promote conservation and energy efficiency. However, the increase in fixed charges tends to result in a shift in cost recovery from high-use to low-use customers. This raises potential distributional concerns, which are valid to the extent that low-use customers are more likely to be low-income customers. In addition, while SFV pricing removes the utility’s disincentive to promote conservation, it also reduces the customer-level incentive to conserve because of the reduced volumetric rates. In contrast, revenue decoupling has small distributional effects and does not affect the customer-level incentive to conserve (as the Commission rightly pointed out in Order 09-020).

[67] The weather adjustment would have the general form of (using summer as an example):
SNA FCER x {*Weather Sensitivity* (in kWh / CDD) x (*Normal CDD – Actual CDD*)}
In a hot month, the customer’s bill would be reduced by the SNA Fixed Charge Energy Rate multiplied by an assumed (or estimated) weather sensitivity parameter, which is the amount by which the customer’s sales are expected to change with CDDs, and further multiplied by the difference between normal and actual cooling degree days (CDDs). A key administrative difficulty is determining an appropriate weather sensitivity parameter, which ideally would be specific to each customer.

treated in the current manner). However, we believe that this is best conducted in conjunction with an indexing of the allowed generation and transmission revenue to an index of industry input costs. In our view, status quo is superior to a bifurcation in which allowed generation and transmission revenue is set at a fixed nominal value in between rate cases.

- Do not adjust PGE's allowed return on equity for the presence of decoupling. We do not find evidence that decoupling materially affected PGE's capital risks.[68]

[68] Note that our sample of decoupled utilities included mechanisms that do not remove the effects of weather. Therefore, it is not clear that PGE's allowed ROE ought to be adjusted downward even if our recommendation to remove the weather adjustment from the SNA is adopted. It is possible that an investigation of the Credit Agency Ratings reports for a sample of utilities with "full" decoupling mechanisms would be enlightening in this regard.

CERTIFICATE OF SERVICE

I hearby certify that on June 6, 2013, I served the foregoing "AN EVALUATION OF PORTLAND. GENERAL ELECTRIC'S DECOUPLING ADJUSTMENT, SCHEDULE 123" upon all parties of record in this proceeding by electronic mail only as all parties have waived paper service.

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland UR 97205
dockets@oregoncub .org

Stephanie S. Andrus (C)
PUC Staff--Department of Justice
Business Activities Section
1162 Court Street NE
Salem OR 97301-4096
stephanie.andrus@state.or.us

Wendy Gerlitz
NW Energy Coalition
1205 SE Flavel
Portland OR 97202
wendy@nwenergy.org

Robert Jenks (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland OR 97205
bob@oregoncub.org

Lance Kaufman (C)
PO Box 2148
Salem OR 97308-2148
lance.kaufman@state.or.us

G. Catriona McCracken (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland OR 97205
catriona@oregoncub.org

Douglas C. Tingey (C)
Portland General Electric
121 SW Salmon 1WTC13
Portland OR 97204
doug.tingey@pgn.com

Jay Tinker
121 SW Salmon St. 1WTC-0702
Portland OR 97204
pge.opuc.filings@pgn.com

Joffew<-. F' Iey
Legal Secretary
Natural Resources Section

Sales Normalization Adjustment (SNA)
Summary of hypothetical Schedule 123 Decoupling

Estimates with weather normalization:

Category	Sch 123 Amounts
Sch 7	$14,988,890
Sch 32	($2,250,560)
Totals	$12,738,330

Estimates without weather normalization:

Category	Sch 123 Amounts
Sch 7	($9,734,908)
Sch 32	($3,687,148)
Totals	($13,422,056)

Portland General Electric
Lost Fixed Generation Revenues from 50 MWa of Long-Term Direct Access Opt Out

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total / Years 6-10
89-P Fixed Generation ($/MWh) with No Escalation	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	
Mwa	50	50	50	50	50	50	50	50	50	50	
Annual Energy	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	
Fixed Generation Decrement	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 75,774,000