BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

June 16, 2017

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I. INTRODUCTION

My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My qualifications are listed in CUB Exhibit 101.

Portland General Electric (PGE or Company) is proposing a rate increase of 7.08% on residential customers, a 5.66% increase for small business, and a 3.39% increase for industrial customers.[1] CUB is concerned that PGE's proposal for allocating the benefits of energy efficiency require residential and small business customers to subsidize an energy resources that service all customers. On top of this, PGE proposes to overcharge residential customers for capacity costs associated with smart grid investments.

CUB's testimony is divided into three sections. The first section addresses the current inequitable circumstances in which residential and small business customers are subsidizing the industrial and large commercial customers' share of energy efficiency as

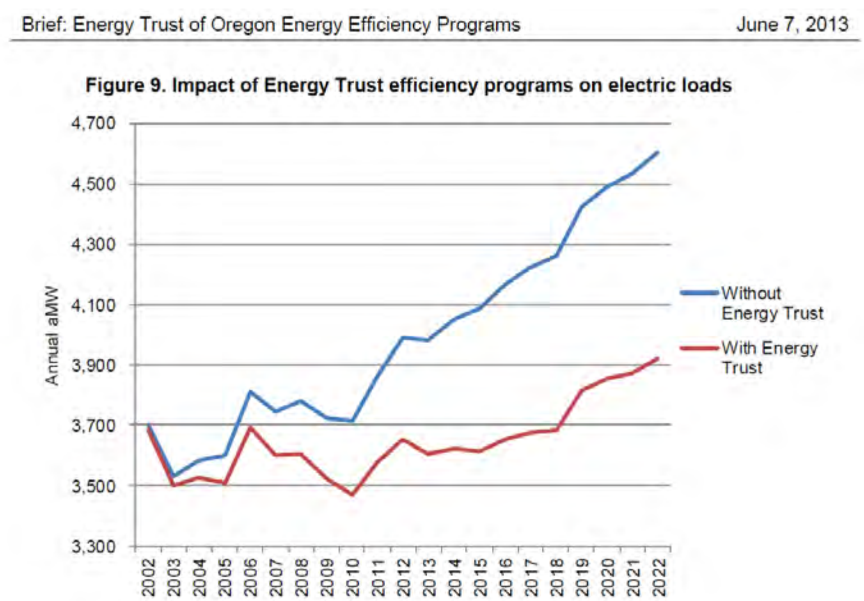
[1] Pg. 12, UE 319 Executive Summary of Portland General Electric

a system resource. The second section discusses CUB's recommended changes to how PGE recovers the cost of its smart grid investments. The third section details CUB's recommended revenue requirement adjustments to PGE's capital structure, employee levels, and other revenue.

II. ENERGY EFFICIENCY SUBSIDY

A. *Energy Efficiency is a Resource*

As the graph below[2] shows, energy efficiency (EE) programs have a substantial and cumulative impact on a utility's electric load.



The EE measures that are installed this year will continue to reduce loads next year, but next year we will add another year of energy efficiency programs. Each year, the difference between what loads would be with and without energy efficiency gets larger. Without efficiency this gap would need to be filled with supply-side resources,

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[2] Energy Trust of Oregon, *Briefing Paper: Energy Efficiency Programs*, Energy Trust Board of Directors Strategic Planning Workshop at 12 (June 7, 2013), https://www.energytrust.org/wp-content/uploads/2017/03/120607_Board_strategic_Planning_Workshop.pdf.

including renewable resources to meet Oregon's RPS. Energy efficiency is more than a personal virtue,[3] it is an important resource for meeting load.

B. *The Interplay Between SB 1149, SB 838 and SB 1547*

Oregon has passed three laws which govern energy efficiency.[4] These laws are inconsistent and when combined, require smaller residential and small commercial customers to subsidize larger industrial customers.

1. *SB 1149*

In 1999, the Oregon Legislature passed SB 1149 which established a "public purpose charge". Under SB 1149, each electric company must collect a public purpose charge from its customers equal to 3% of its total revenues. The utility must also direct 63% of the 3% public purpose charge to new cost-effective conservation and new market transformation programs.[5]

It is important to note that the law required the 3% charge to be levied not just on the energy portion of the bill but on "distribution, ancillary services, metering and billing, transition charges and other types of cost."[6] This means that EE collected through the public purpose charge is charged to customers in a different manner than electric generation. Electric generation is charged to customers based on their need for energy and capacity, but not on their use of distribution plants. The result of this is that customer

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[3] Vice President Dick Cheney said, "[c]onservation may be a sign of personal virtue, but it is not a sufficient basis for a sound, comprehensive energy policy." Joseph Kahn, *Cheney Promotes Increasing Supply as Energy Policy, The New York Times* (May 1, 2001), http://www.nytimes.com/2001/05/01/us/cheney-promotes-increasing-supply-as-energy-policy.html?mcubz=2.

[4] *See* SB 1149, SB 838, and SB 1547.

[5] 1999 Or. Laws Ch. 865 (S.B. 1149) § 3(3)(b)(A), https://www.oregonlegislature.gov/bills_laws/lawsstatutes/1999orLaw0865.html.

[6] *Id.* at § 3(2)(a).

classes with less energy demand and higher distribution usage will pay more for demand-side investments (energy efficiency) than those same customers would pay for a supply-side investment (Carty or Tucannon). The customers who use less energy but more distribution are the customers with smaller individual loads, residential, and small commercial.

2. *SB 838*

Since 2007 the Renewable Energy Act, SB 838, has allowed for the collection of additional funds for investment in cost-effective EE, but only from customers whose usage falls below 1aMW. SB 838 provides that a retail electricity consumer with a load greater than one average megawatt: (1) "[i]s not required to pay an amount that is more than three percent of the consumer's total cost of electricity service…"; and (2) [d]oes not receive any direct benefit from energy conservation measures…"[7]

3. *Combining SB 1149 and SB 838*

During the 2007 Oregon Legislative Session, PGE proposed amending SB 838 to include additional energy efficiency but exempting large customers (above 1aMW) from being charged for the additional EE. CUB expressed concern at that time that exempting large customers would be unfair to small customers (less than 1 aMW). Specifically, CUB was concerned that new industrial programs would be added to public purpose programs and all customer classes would pay for them, but new residential and small business programs would come from SB 838 funds, and only small customers would pay

[7] 2007 Or. Laws Ch. 301 (S.B. 838) § 46(a)-(b), https://olis.leg.state.or.us/liz/2007R1/Downloads/MeasureDocument/SB838/Enrolled; ORS § 757.689(2).

for them. This could lead to small customers funding the bulk of energy efficiency. During the legislative session, PGE assured CUB that this would not happen:

> The intent here is 'no pay, no play.' In asking the OPUC to exempt these customers, we would also ask that they work with the ETO to cap public purpose charge expenditures on behalf of this group at current levels. If later it appeared that more cost effective EE was available through these customers, and they were willing to pay for it, adjustments could be made.[8]

An Energy Trust of Oregon (ETO) Briefing Paper explains how SB 838's limitation on industrial programs means that the ETO would no longer be able to acquire all cost effective energy efficiency:

Passed in 2007, Oregon's Renewable Energy Act, SB 838, authorized the OPUC to approve the collection of additional electric efficiency funds from PGE and Pacific Power customers using less than one aMW per year. Customers using more than 1 aMW do not pay these supplemental charges and may not benefit from this funding. SB 838 does not address voluntary payment of supplemental efficiency charges.

> Energy Trust efficiency programs are not funded on a strict funds-in, funds-out basis, yet the SB 838 limitation implies such a logic. To ensure compliance with the limitation, after 2007, Energy Trust, the OPUC, PGE, Pacific Power and stakeholder organizations including the Citizens' Utility Board of Oregon, CUB, and the Industrial Customers of Northwest Utilities, ICNU, informally agreed that Energy Trust will keep funding for large customer incentives to the historic proportion of SB 1149. If large customer incentives exceed the pre-2007 percentage of SB 1149 funding, Energy Trust would have two years to align these incentives with the historic allocation.
>
> Due to success of the programs in delivering high volume and low-cost savings to large customers, incentives to these customers have grown. Given current trends in program investment, spending for large customers in PGE's service territory will need to be curtailed in approximately 2015

[8] UE 283 – PGE/2201/Tinker/1.

> or sooner. This funding limitation means that Energy Trust may not be able to secure all cost-effective efficiency from these customers.[9]

4. *SB 1547*

In 2016, the legislature passed SB 1547, which phased out coal as a resource and raised the RPS to 50%. The bill also required that all cost effective EE be acquired. Specifically, SB 1547 states that:

> Energy efficiency programs promote lower energy bills, protect the public health and safety, improve environmental benefits, stimulate sustainable economic development, create new employment opportunities and reduce reliance on imported fuels; and
>
> (b) Demand response resources result in more efficient use of existing resources and reduce the need for procuring new power generating resources, which, in turn, reduces energy bills, protects the public health and safety and improves environmental benefits.
>
> (3) For the purpose of ensuring prudent investments by an electric company in energy efficiency and demand response before the electric company acquires new generating resources, and in order to produce cost-effective energy savings, reduce customer demand for energy, reduce overall electrical system costs, increase the public health and safety and improve environmental benefits, each electric company serving customers in this state shall:
>
> (a) Plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible; and
>
> (b) As directed by the Public Utility Commission by rule or order, plan for and pursue the acquisition of cost-effective demand response resources.[10]

5. *SB 1149, SB 838, and SB 1547 Together*

When the three previously discussed statutes are taken together, the legislature has issued the Commission the following directives: (1) fund cost effective EE through

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[9] Energy Trust of Oregon, *Briefing Paper: Energy Efficiency Programs*, Energy Trust Board of Directors Strategic Planning Workshop at 27 (June 7, 2013), https://www.energytrust.org/wp-content/uploads/2017/03/120607_Board_strategic_Planning_Workshop.pdf.

[10] 2016 Or. Laws Ch. 28 (S.B. 1547), Section 19(2)(a), https://www.oregonlegislature.gov/bills_laws/lawsstatutes/2016orLaw0028.pdf.

the public purpose charge[11]; (2) allow for additional cost effective EE when funded by residential and small commercial customers[12]; (3) prevent large customers from receiving any benefit from EE that exceeds their contribution to the public purpose charge[13]; and (4) require all cost effective EE resources to be acquired[14].

Unfortunately, these statues are in conflict. The public purpose charge does not provide enough money to support all cost effective energy efficiency. Last year the public purpose charge funded $ 54,534,546 of energy efficiency, while the additional EE authorized under SB 838 funded $ 70,828,365.[15] While SB 838 does provide additional funding for EE programs, those programs cannot benefit large customers. ETO recently confirmed that it has reached the SB 838 cap on industrial programs,[16] requiring that some programs for large customers will soon go unfunded.[17] But if the ETO acts to implement the SB 838 cap then it will be in violation of the SB 1547 mandate to acquire *all* cost-effective energy efficiency.

6. *The Growth in 838 Funding*

Today, SB 838 is the largest source of energy efficiency funding. This wasn't what was expected. Originally, SB 838 was designed to take advantage of a limited

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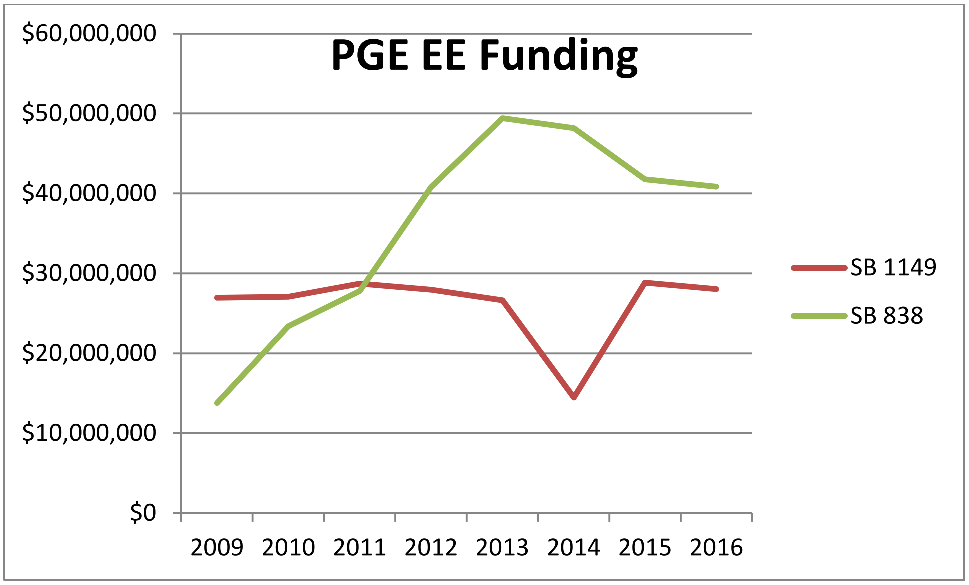
[11] S.B. 1149.
[12] S.B. 838.
[13] S.B. 838.
[14] S.B. 1547.
[15] Includes both PGE and PacifiCorp: *Energy Trust of Oregon, 2015 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors* (Apr. 15, 2016) Appendix 10 at 71, http://assets.energytrust.org/api/assets/reports/2015.Annual.Report.OPUC.with.NEEA.pdf.
[16] CUB Exhibit 102.
[17] Energy Trust of Oregon, *Briefing Paper: Energy Efficiency Programs*, Energy Trust Board of Directors Strategic Planning Workshop at 27 (June 7, 2013), https://www.energytrust.org/wp-content/uploads/2017/03/120607_Board_strategic_Planning_Workshop.pdf.

opportunity for some additional residential and small business programs. But it quickly became the largest source of EE funding[18]:



C. *Different Customer Classes Buy Different Sets of Resources*

As CUB previously stated, Energy Efficiency is a resource. The chart above demonstrates that residential and small commercial customers, the customers who pay SB 838 funds, are buying more EE than the large industrial customers who only contribute to SB 1149 funds. Small and large customers are purchasing a different resource mix for the Company.

In UM 1690, PGE advocated allowing industrial customers to purchase a different resource mix to enable PGE to serve industrial customers with renewable energy.[19] The difference between that proposal and what PGE is proposing in this rate case is that PGE proposed crediting industrial customers with the renewable resources that they were

[18] CUB Exhibit 103.
[19] PGE's UM 1690 Comments for Phase 2 of VRET at 2.

paying for, but PGE has not developed any proposals to credit residential and small business customers for the resources that they are purchasing.

D. *UE 283/UM 1713: The Search for the Solution*

CUB raised this issue in docket UE 283 and proposed solving the problem by incorporating the difference in resource mix into the marginal cost of service study. Oregon allocates revenue requirement between customer classes based on a marginal cost of service study. Marginal costs are forward-looking. For energy costs, the idea is to identify the cost of serving an incremental increase in load. CUB examined the marginal cost of service study and adjusted it to reflect that residential and small business customers were purchasing less expensive resources that included more energy efficiency, and industrial customers were purchasing more expensive resources.

ICNU opposed CUB's proposal, arguing that it violated SB 838. ICNU's witness, Mullins, stated:

> My understanding is that SB 838 not only limits the direct benefit to large customers from SB 838 funds, it also prohibits them from paying in rates an amount above the three percent SB 1149 public purpose charge to fund energy efficiency. Thus, the substance of the CUB proposal, in requiring industrial customers to pay additional amounts for energy efficiency, violates these funding limitations.[20]

CUB disagrees. CUB's proposal in UE 283 did not change in any way how the costs of energy efficiency programs are distributed. CUB did not ask industrial customers to contribute any additional dollars for energy efficiency. Instead, CUB's proposal was an attempt to ensure that the benefits of EE reflect the funding from different customer classes. If different customer classes are purchasing different resource mixes, then both the costs and benefits of that resource mix should be allocated. The

[20] UE 283 – ICNU/300/Mullins/5.

industrial customers should not receive a benefit from SB 838 EE spending, since they are not contributing. This is similar to a circumstance where roommates are considering dinner. Two people agree to order a pizza, and the third person declines. After the pizza arrives, the person who declined demands one-third of the pizza.

Ultimately, UE 283 ended with an agreement to kick the issue into a special investigation, UM 1713. UM 1713 discussed the issues, with several parties preferring legislative solutions that removed the cap from industrial funding rather than reallocating the benefits. Ultimately most of the parties to UM 1713 agreed to seek a legislative solution. However, that effort was not successful after ICNU pulled its support for the legislation approximately one week before the 2016 legislative session.

E. *The Problem Remains*

At this point, the problem remains. Residential and small commercial customers are being asked to purchase more than their share of energy efficiency resources while not being credited with those resources. This is a violation of just and reasonable ratemaking. The ETO is faced with not being able to acquire all cost effective energy efficiency because of the cap on industrial efficiency imposed by SB 838. At the same time, SB 1547 requires that all cost effective energy efficiency be acquired.

CUB believes the solution to the first problem is to credit the customers who pay for energy efficiency with the system benefits of energy efficiency, and the solution to the cap on industrial efficiency is to reexamine the interpretation of the direct benefits prohibition contained in SB 838.

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F. *Direct Benefits Prohibition*

The Commission must ensure that customers above 1aMW do "not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates" under SB 838. [21] Based on the legislative history, this provision has been interpreted as ensuring that there are no additional energy efficiency programs aimed at large customers funded out of SB 838, and that residential and small commercial programs not be shifted to SB 838 as a way to allow more funding of industrial programs through SB 1149's public purpose charge.

PGE invests in energy efficiency because it is a system resource. Energy efficiency is an integral part of meeting the Company's load in the least-cost manner. The primary benefit of PGE conducting energy efficiency programs is not that some customers sell energy efficiency services to the utility, but that the utility is meeting load at the least cost. As customers, the ***direct benefit*** of EE is lower rates, because more expensive supply side resources are avoided.

By recognizing that lower rates are the direct benefit of EE, and lower rates are the reason that utility customers fund EE, PGE could move beyond the SB 838 cap on industrial funding. This could solve the SB 838 and SB 1547 conflict. However, this would require that the direct benefit, the lower cost system benefit of SB 838 funding, would have to be excluded from customers above 1aMW, thus solving the fairness question.

[21] 2007 Or. Laws Ch. 301 (S.B. 838) § 46(2)(b), https://olis.leg.state.or.us/liz/2007R1/Downloads/MeasureDocument/SB838/Enrolled; ORS § 757.689(2)(b).

G. *Marginal Cost of Service Approach*

In UE 283, CUB proposed incorporating energy efficiency into the marginal cost of service study, recognizing that residential and small commercial customers are purchasing a different resource mix than large customers. This examination looked at long term marginal costs, so was comparing the resources small customers are purchasing to the alternative resources that the IRP suggested the utility would otherwise build. CUB continues to believe that this is a reasonable approach consistent with the tradition of basing Oregon cost of service allocation on long-term marginal costs. CUB Exhibit 103 includes CUB testimony and exhibits from UE 283 that detail this approach.

H. *CUB's Alternative Approach: Crediting Customers with the Value of What They Purchase.*

As an alternative to a marginal cost approach, CUB has identified in this docket an approach that examines the value of the SB 838 resource, which will be consumed in the test year. CUB then compares the test year to the cost of alternatives in 2018.

CUB Exhibit 104 shows that there is 1,178,542 MWh of SB 838 EE that is a resource to be utilized in the 2018 test year. It was acquired with a levelized cost of \$26.1/MWh. This can be compared with a 2018 generation and capacity marginal cost of \$32.33/MWh, which represents the cost of energy to serve this load if the EE dollars had not been spent.[22] Therefore, the 2018 benefit provided by this embedded EE is \$7,336,566. CUB believes that a bill credit should be established that provides this amount to the customers who paid for this benefit.

Based on 2015 contributions to SB 838, each rate class would receive approximately the credit listed below. Though we note that some rate schedules contain

[22] UE 319 – PGE/1301/Cody–Macfarlane/2.

individual customers who are above 1aMW (do not purchase SB 838 resource) and would not be eligible for this credit.

Rate Schedule[23]		
Schedule 7	56.47%	$ 4,142,790
Schedule 15/515	0.20%	$ 14,379
Schedule 32/532	10.89%	$ 798,608
Schedule 38/538	0.35%	$ 25,979
Schedule 47	0.17%	$ 12,239
Schedule 49/549	0.45%	$ 32,914
Schedule 83/583	15.56%	$ 1,141,616
Schedule 85/485/585	14.83%	$ 1,087,660
Schedule 89/489/589	0.00%	$ -
Schedule 90/490/590	0.00%	$ -
Schedule 91/95/591/595	1.08%	$ 79,102
Schedule 92/592	0.02%	$ 1,278
Schedule 485	0.00%	$ -
Schedule 489	0.00%	$ -

I. *CUB's Recommendation*

The current system of distribution EE funding and benefits is unfair to residential and small commercial customers. In addition there is a conflict between the current interpretation of SB 838 and SB 1547. CUB believes this can be solved by recognizing that the direct benefit of energy efficiency is a reduction in the utility's cost of service and by adopting a mechanism to credit customers who pay for energy efficiency with the benefits of those investments. CUB has proposed two methods of doing this (marginal and embedded) and recommends that the Commission adopt one of these approaches or open a new docket specifically to develop a mechanism to ensure that the benefits of energy efficiency investments flow to the customers who pay for those investments.

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[23] CUB Exhibit 105.

III. SMART GRID INVESTMENTS

PGE's marginal cost of service study allocates costs to customers by first assigning costs to certain buckets: energy, capacity, design demand, or customer. Broadly speaking the cost is then spread across that bucket. Energy costs are assigned to customers by their energy usage, capacity is assigned based on peak usage, design demand is allocated based on each rate classes' proportional estimated peak, and customer costs are assigned based on the number of customers.

PGE's marginal cost of service study fails to recognize that the changing nature of distribution and customer service investments requires a change in the assignment of costs to these buckets. The consequences are that investments that are being made to enable demand response and meet peak load are being misallocated as customer costs not as capacity costs. This has significant consequences. If a utility has a choice to serve peak capacity with either demand response or a gas-fired peaker, it should pick the choice that has the least cost/least risk. But demand response is allocated on a per customer basis (total cost divided by number of customers) and the gas-fired peaker is allocated on a capacity basis (total cost divided by peak usage). As a result, low usage customers would likely favor the gas peaker and high usage customers will likely favor the demand response. Oregon uses a marginal cost of service approach to send appropriate price signals to customers, but this cannot be done when the price signals support investments that are suboptimal (not least cost).

A. PGE's Distribution and Customer Service Marginal Cost of Service

On the distribution system, PGE allocates some costs on a dollars/KW (design demand) bases and some on a dollars/customer basis. AMI meters, for example, are allocated on a dollars per customer basis.[24] This is historically how meters were allocated, when meters were simple and used to measure energy usage for the sole purpose of billing. All customers, no matter how much they used, needed the same monthly meter read in order for their monthly bill to be produced. But PGE's smart meters are supposed to be enabling much more. When PGE requested cost recovery of smart meters, it identified the customer and system benefits beyond meter reading:

- Demand response programs;
- Information-driven energy savings;
- Improved distribution asset utilization; and
- Improved outage management.[25]

Demand response programs are a way to meet capacity needs and should be allocated to capacity. Information-driven energy savings generated by PGE's Energy Tracker[26] should be allocated to energy. Improved distribution asset utilization and improved outage management should be allocated in the same manner as the general distribution assets (design demand), not as customer-related.

Similar issues surround PGE's customer service costs. This represents PGE's costs "in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing."[27] These costs are allocated to customers on a dollars/customer basis.[28] But some of these costs are utilized for the same sort of enhanced customer and system benefits as AMI meters. PGE states that Network Data Operations are allocated based on the number of meters[29], but like

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[24] UE 319 – PGE/1300/Cody–Macfarlane/12; UE 319 – PGE/1301/Cody–Macfarlane/3.
[25] UE 189 – PGE/Exhibit 103/Carpenter–Tooman/1.
[26] CUB Exhibit 106.
[27] UE 319 – PGE/1300/Cody–Macfarlane/14.
[28] UE 319 – PGE/1301/Cody–Macfarlane/3.
[29] UE 319 – PGE/1300/Cody–Macfarlane/15.

AMI meters, this data is used for demand response, information-driven savings, improved distribution asset utilization, and improved outage management. The Customer Information System (CIS) is allocated on a dollars/customer basis[30] even though it specifically includes the ability to manage demand response pricing.[31]

B. Smart Grid Requires New Cost Allocations

CUB Exhibit 106 is a presentation by Jim Lazar of the Regulatory Assistance Project (RAP) on Recovering Smart Grid Costs in Electric Rates. Mr. Lazar identifies several benefits associated with Smart Grid investments:

- Reduced O&M Expense for meter reading;
- Remote shut-off and turn-on;
- Reliability Improvement;
- Distribution Automation;
- Peak load reduction through Time of Use and Critical Peak Pricing;
- Loss reduction: Voltage Control and Power Factor Correction; and
- Loss Reduction: Phase balancing on the fly.

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[30] *Id.*
[31] UE 319 – PGE/900/Stathis–Dillin/13.

Below is a chart that shows how Mr. Lazar believes that elements of smart grid should be classified for cost allocation purposes:

The Methods For Classification and Allocation Must Change

Smart Grid Element	Pre-Smart Grid Element	"Traditional" FERC Account	Traditional Classification	Smart Grid Classification
Smart Meters	Meters	370	Customer	Demand / Energy / Customer
Distribution Control Devices	Station Equipment	362	Demand	Demand / Energy
Data Collection System	Meter Readers	902	Customer	Demand / Energy / Customer
Meter Data Management Syste	General Plant	391 - 397	Subtotal PTDC	Demand / Energy / Customer
Smart Grid Managers	Customer Accounts Supervision	901	Customer	Demand / Energy
Energy Storage Devices (Batteries; Ice Bear)	Installations on Customer Premises	371	Customer	Demand / Energy

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13

C. Customer Engagement Transformation.

According to PGE:

> PGE's Customer Engagement Transformation (CET) is a comprehensive multiyear program comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large customer systems:
>
> - Customer Information System (CIS)
> - Meter Data Management System (MDMS)[32]

The biggest elements of these are the CIS and MDMS capital projects. These two projects have been delayed since PGE's last rate case and are now not expected to be in service until the second quarter of 2018.

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[32] UE 319 – PGE/900/Stathis–Dillin/7.

CET will enable and improve demand response offering. CET will allow customer enabled third parties to more easily access customer interval meter data which will allow for demand response aggregation.[33] The current MDMS cannot expand sufficiently to allow DR pricing pilots to become full-scale programs.[34] The new MDMS, combined with the new CIS, provide significant DR benefits:

> The Customer Care & Billing Customer Information System (CIS) and the MDM system will provide a more systematic approach to program management for PGE's demand response (DR) programs, including:
>
> - Improving insight into customer enrollment and un-enrollment in DR programs and the timing associated with the enrollment process;
> - Improving clarity of the configuration of DR programs, such as account, premise and meter set-up;
> - Allowing for a more streamlined and timely process for developing and setting-up new rate schedules;
> - Allowing for transparency of data tracking between the CIS and MDM systems for PGE employees;
> - Capturing interval data for all customers in a single application with more robust and automated validation processes; and
> - Improving timing coordination with PGE's third-party vendors who assist PGE with the execution of DR programs to determine the best load shifting and load reduction strategies as well as everyday energy saving opportunities for our customers.[35]

In addition, the new CIS system, combined with the MDMS will improve PGE's offering of optional programs such as Clean Wind, and demand response programs such as Critical Peak Pricing and Peak-Time Rebates.[36]

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[33] CUB Exhibit 108.
[34] CUB Exhibit 109.
[35] CUB Exhibit 109.
[36] CUB Exhibit 110.

D. PGE is Incorrectly Assigning Storage to Customer O&M

Within PGE's marginal cost of service study, Customer O&M costs are allocated on a dollars/customer basis (total cost divided by number of customers). Unfortunately, this is where PGE has decided to place storage costs:

> Energy Storage has $300,000 budgeted in Customer Service O&M specifically dedicated toward ongoing operational support of the storage deployment(s) we anticipate will be underway in response to HB 2193. The R&D budget for energy storage includes projects that advance PGE's ongoing knowledge and skills acquisition related to emerging storage technologies. [37]

Storage has a variety of functions including meeting peak demand, integrating renewables, and improving reliability. PGE's IRP has an entire chapter on storage which begins with this description:

> Energy storage resources provide the ability to more efficiently meet demand with generation by shifting both demand and generation in time. This capability has the potential to reduce costs associated with load and renewable variability and unpredictability, as well as thermal plant and transmission operating constraints.

But there is nothing here that suggests storage is primarily customer related, rather than demand and energy related.

E. CUB's Recommendation

PGE has failed to update its Marginal Cost of Service Study to reflect the purpose of some of its current investments and programs. CUB recommends that a number of costs be reallocated.

AMI meters allow for demand response programs, information-driven energy savings, improved distribution asset utilization, and improved outage management. CUB

[37] CUB Exhibit 111.

recommends that these be reclassified as 50% customer related, 25% capacity related, 12.5 % energy related, and 12.5% design demand related.

The CIS and MDMS programs have similar functionality as AMI meters and CUB recommends similar reclassification: 50% customer related, 25% capacity related, 12.5 % energy related, and 12.5% design demand related.

Storage is primarily used to integrate renewables and move energy or demand to a different time period. CUB recommends that storage be allocated as 50% energy related and 50% capacity related. In addition, CUB recommends that PGE be required to conduct a study to determine where all smart grid related costs are within its system and how those costs should be allocated.

IV. REVENUE REQUIREMENT ADJUSTMENTS

A. Capital Structure.

PGE has not supported its proposal to carry a capital structure that is 50% equity and 50% debt[38] with any analysis that demonstrates that a 50/50 capital structure is the least cost/least risk method to finance its capital investments. There are trade-offs of risk and cost to a utility's capital structure. Utilities finance with a mixture of debt and equity. Debt is cheaper, but carries a higher risk because debt payments are an obligation which takes precedence over earnings.[39] A utility has to meet its debt payment, but it can reduce dividends. Because of this tension, there is a trade-off between the cost of debt and the capital structure – a trade-off between price and risk. When cost of debt is lower, a utility may find that a little more risk is reasonable.

[38] UE 319 – PGE/100/Piro-Lobdell/14.

[39] David Murray, et al., *Linking Risk and ROE, Financial-risk Coverage is Falling Short in Utility Returns*, *Public Utilities Fortnightly* (Jan. 2008), https://www.fortnightly.com/fortnightly/2008/01/linking-risk-and-roe.

PGE must provide *some* analysis that supports its proposed capital structure as a reasonable mixture of cost and risk. But, aside from its limited testimony, the Company has been unable to provide CUB with additional support for its proposed capital structure.[40] PGE states that it intends to maintain a 50/50 capital structure for the following reasons:[41]

- To support PGE's capital needs and offset the leverage and risk to finance its capital expenditure program;
- To offset the leverage imputed by the rating agencies due to purchased power;
- To maintain solid financials in the face of a variety of business risks; and
- Because it aligns with PGE's survey of capital structure across the industry.[42]

CUB sees a number of inconsistencies with PGE's stated reasons for a 50/50 capital structure. First, according to CUB's analysis, PGE's actual equity level is usually below 50 percent. CUB Confidential Exhibit 112 shows PGE's actual capital structure since 2010. The average equity level is [redacted] During this period of time PGE has had 4 rate cases where it has always forecast its regulated capital structure as 50/50.[44]

Second, contrary to PGE's assertions, the data from across the industry shows a wide range of equity levels, from a low of 30.16 to a high of 58.18[45]. While PGE's proposed 50 % equity is within this range, and is slightly below the average of the data set, this does not mean that it is the least cost/least risk to financing capital investment.

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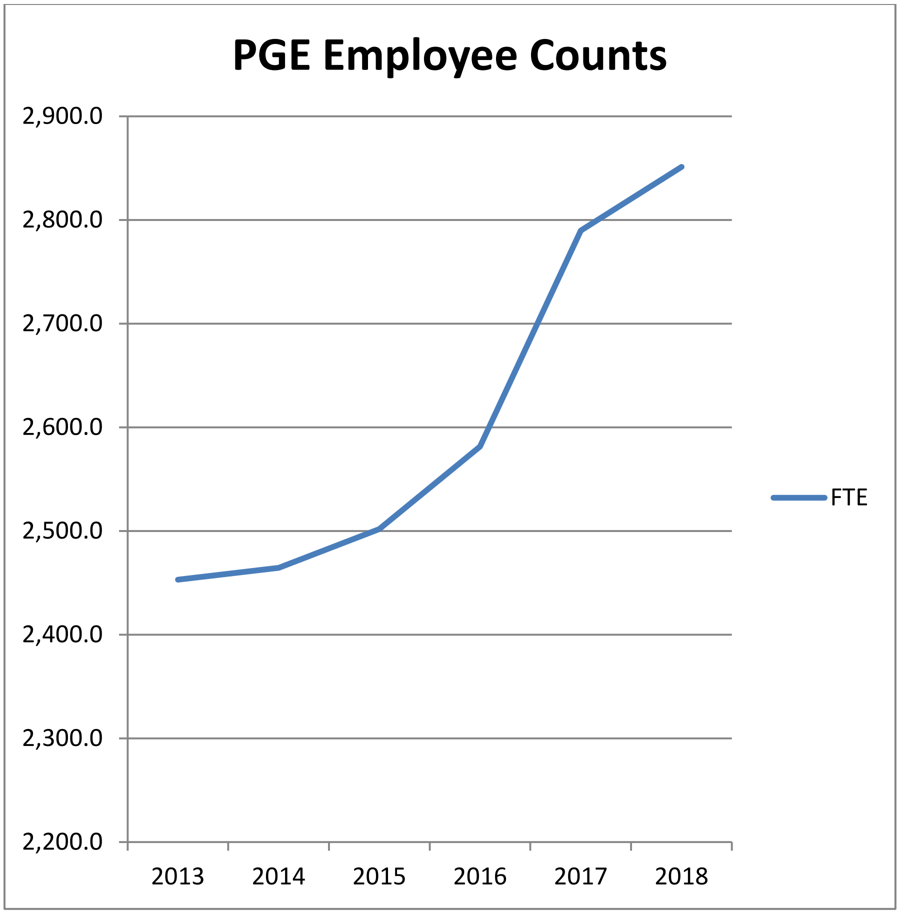
[40] CUB Exhibit 112.
[41] *See* UE 319 – PGE/1000/Hager-Liddle/21-24.
[42] *See* PGE's Attachment 005-A (examining all utilities in pending rate cases and rate cases going back as far as 2015).
[43] CUB Confidential Exhibit 112.
[44] PGE's UE 215 Pretrial Brief at 12; PGE's UE 262 Executive Summary at 9; PGE's UE 283 Executive Summary at 11; PGE's UE 295 Executive Summary at 10.
[45] CUB Exhibit 114.

Financing with debt is clearly lower cost than financing with equity. PGE offers no real analysis of the trade-off between cost and risk associated with interest rates and capital structure. Without analysis, it is not clear what the ideal capital structure is. It is known that a lower equity percent is lower cost to customers. And it can be assumed that an equity percentage of [redacted] does not carry too much risk, because that is the average equity percentage that PGE has actually carried since 2010. Accordingly, CUB recommends the Commission adjust PGE's proposed capital structure to require a [redacted] equity level.

B. Employee Levels

CUB's analysis finds that PGE's 2017 and 2018 employee level projections are inflated and should be reduced. PGE's forecasted increase in employee levels is a significant basis for the Company's rate increase. PGE projects its employee levels will increase by more than 10% between 2016 and 2018.[46] According to the Company, there were 2,581.3 employees in 2016, and it projects 2,851.1 employees in 2018 – an increase of 269.8.[47] The 2016 historic number represents the actual number of hours worked per year divided by the number of work hours during the year (excluding overtime).[48] Below is the PGE employee count from 2011 through the 2018 test year.[49]

[46] UE 319 – PGE/400/Mersereau–Jaramillo/14.
[47] *Id.* at 11.
[48] *Id.*
[49] CUB Exhibit 115.



The chart above shows a large jump during the 2017 calendar year. PGE projects increasing its number of employees by 231.7 in 2017, with 55 positions added by the end of January 2017, and 176.7 additional positions through the remainder of the year.[50] To manage this, PGE has to add 19.25 new hires per month – even more if some employees quit or retire. However, in contrast to the Company's forecasted employee levels, PGE is already behind in its hiring efforts. For example, by the end of March 2017, PGE had 2,627.47 FTE.[51] That puts PGE's March FTE count at a lower level than the Company had projected for the end of January 2017.

[50] UE 319 – PGE/400/Mersereau–Jaramillo/12.
[51] CUB Exhibit 116.

PGE's own website demonstrates its current hiring shortfall. The Company currently lists 36 job openings on its website.[52] Seventeen of the open positions are listed as "open until filled"[53] – suggesting that the original application timeline has passed and PGE is still looking to fill the job. It should be noted that the Company's open positions are not necessarily *new* positions. A Company of PGE's size will always have positions open as some staff quit and retire. PGE Exhibit 401 lists an unfilled position rate of 7.7%. The Bureau of Labor Statistics cites 4.0 % of jobs as currently vacant.[54] This suggests that, at any point in time, PGE should have somewhere between 103 and 198 job openings (based on 2016 FTE count) just to maintain its current size.[55]

All of the data indicates that PGE is unlikely to reach its forecasted employee levels by the end of the test year. CUB looked at the Company's hiring increase between 2013 and 2016, the most recent years with real data and plotted a trend line:

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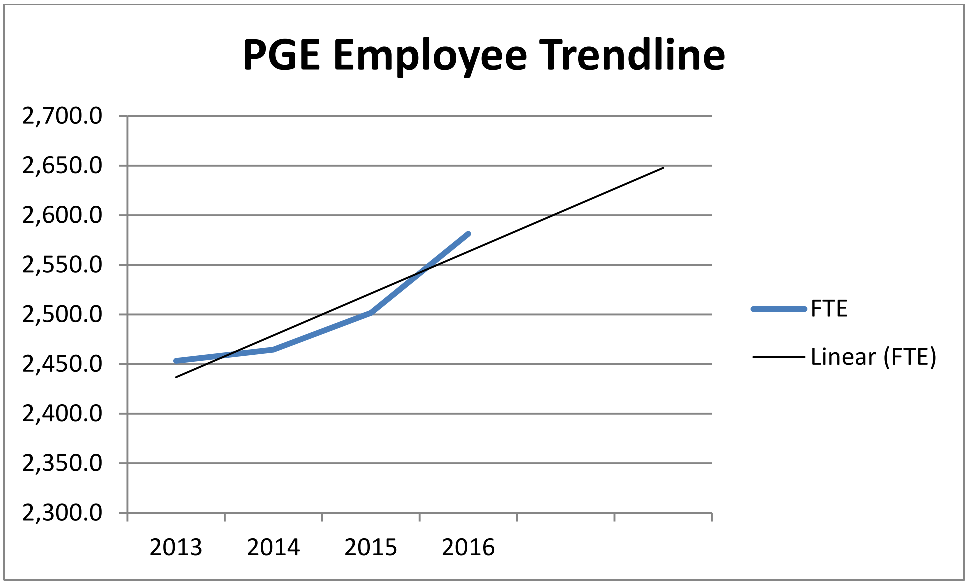
[52] Portland General Electric, *Career Opportunities*, https://pgn.igreentree.com/css_external/CSSPage_Welcome.asp (last visited 6/15/2017).

[53] *Id.*

[54] U.S. Dept. of Labor, Bureau of Labor Statistics, Job Openings and Labor Turnover Summary (June 6, 2017, 10:00 AM), https://www.bls.gov/news.release/jolts.nr0.htm.

[55] CUB wants to acknowledge that it may not be surprising if the Company is having difficulty filling jobs. The current tight labor market means many business are having difficulty filling their positions. *See, e.g.*, Akin Oyedele, *Employers are Having a Harder Time Finding Skilled People to Hire, Fed Says*, BUS. INSIDER (Apr. 19, 2017, 2:00 PM), http://www.businessinsider.com/beige-book-fed-april-19-2017-4.



Based on this trendline, the average number of FTE for 2018 is 2625 which is approximately what PGE had in March of 2017 with approximately 2650 by the end of 2018.

In UM 1811, CUB recommended that the new employees PGE contemplated for EV technical assistance should be added to base rates. Therefore, CUB recommends that PGE's employment level be set at 2651, based on the trendline for the end of 2018, and the additional employee for EVs. The effect of this adjustment on PGE's revenue requirement will depend on whether the lower number of new employees changes the split between capital and expense and whether there are adjustments to PGE's proposed wages and benefits.

C. Other Revenue

III. **Other revenues are revenues PGE obtains from its system that do not come from customers. It includes items like pole attachments and steam sales. Since 2008, PGE has under forecast other revenues 8 out of**

9 years.[56] This suggests that its forecast variation is not random, but systematic. Therefore, CUB recommends adjusting PGE's forecast of other revenue based on the historic under forecast from 2008 to 2016. This increases other revenues by $1.43 million which reduces the revenue requirement by an equal amount.CONCLUSION

CUB's analysis shows that PGE's proposed rate increase for 2018 unfairly asks residential customers to subsidize large customers' share of both energy and capacity resources. In addition, CUB's review of PGE's revenue requirement finds that PGE's request is inflated. CUB makes the following proposals.

Energy Efficiency Subsidy. CUB recommends that the Commission adopt a mechanism to ensure that the customers who are paying for a resource mix with more energy efficiency are credited with the benefits of that resource mix. CUB offers two models for calculating that credit. CUB recommends the Commission adopt one of these mechanisms, or the Commission opens an investigation to determine a methodology for crediting paying customers with the benefits for which they have paid.

Smart Grid Subsidy. CUB recommends that the Commission require PGE to change how it allocates costs associated with AMI meters, the CIS and MDMS programs, and energy storage to reflect that these programs provide energy and capacity benefits.

Revenue Requirement. CUB recommends that the Commission reduce PGE's revenue requirement by adjusting its capital structure based on historic equity levels, reduce its forecasted new employees to be consistent with a more reasonable trend, and adjust the forecast of other revenues to be consistent with historic trends.

[56] CUB Exhibit 117.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UE 296, UE 308, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

Energy**Trust** of Oregon

Agenda

Conservation Advisory Council
Wednesday, June 21, 2017
1:30 p.m. – 4:30 p.m.

421 SW Oak St., #300, Portland, OR 97204

1:30 Welcome and Introductions
New Conservation Advisory Council facilitator—Hannah Cruz, Sr. Communications Manager

1:35 Announcements, Old Business and Short Takes *(discussion)*
May 2017 CAC minutes, reminder on budget review survey, September CAC meeting date change, Residential PMC RFP update and Board Strategic Planning Workshop next steps

1:50 2017 Legislative Update *(information)*
Staff will provide an update on the state legislative session and bills that are being monitored. Under our grant agreement with the OPUC, Energy Trust does not take positions on legislation or engage in political issues. During legislative sessions, we monitor bills that could impact Energy Trust and respond to legislative requests for information.

2:00 Residential Lighting Market Update *(information)*
Staff will present an overview of recent trends in residential lighting in the Products program.

2:30 Cannabis Market Update *(information)*
Staff will present an update on the cannabis market for production grow facilities.

2:45 New Buildings Program Update *(discussion)*
Staff will present an update on the New Buildings program, including market engagements, community building, training and education.

3:15 Business Customer Reports Overview *(information)*
Staff will provide an overview of Energy Trust's Business Customer Reports, a recently launched business customer engagement tool.

3:30 Large Customer Funding Analysis *(discussion)*
Staff will describe the history of the large customer funding analysis, present the 2016 results and review next steps given the report's findings that Energy Trust reached the funding threshold.

4:15 Public Comment

4:30 Adjourn

The next scheduled meeting of the Conservation Advisory Council is Wednesday, August 2, 2017

Conservation Advisory Council Meeting Notes

May 3, 2017

Attending from the council:
Jess Kincaid, Bonneville Power Administration (for Brent Barclay)
JP Batmale, Oregon Public Utility Commission
Holly Braun, NW Natural
Roger Kainu, Oregon Department of Energy
Julia Harper, Northwest Energy Efficiency Alliance
Andria Jacob, City of Portland
Don Jones, Jr., Pacific Power
Don MacOdrum, Home Performance Guild of Oregon
Garrett Harris, Portland General Electric
Lisa McGarity, Avista
Stan Price, Northwest Energy Efficiency Council
Allison Spector, Cascade Natural Gas
Charlie Grist, NW Power and Conservation Council
Tony Galluzzo, Building Owners and Managers Association

Attending from Energy Trust:
Mike Bailey
Tom Beverly
Peter West
Cameron Starr
Marshall Johnson
Mike Colgrove
Kathleen Belkhayat
Oliver Kesting
Jay Ward
Hannah Cruz
Kate Hawley

Others attending:
Alan Meyer, Energy Trust board
John Frankel, NW Natural
Chris Smith, Energy350
Scott Brogan, ICF
Jason Jones, Ecova
Rick Hodges, NW Natural

1. Welcome and introductions

Peter West convened the meeting at 1:30 p.m. The agenda, notes and presentation materials are available on Energy Trust's website at: https://www.energytrust.org/about/public-meetings/conservation-advisory-council-meetings/.

2. Old business and announcements

Hannah Cruz announced an upcoming opportunity to provide input on Energy Trust's annual budget process and how it intersects with utility planning. An internal project team has been convened to discuss the budget process, timing, objectives and improvements. Conservation Advisory Council members and other Energy Trust stakeholders will be emailed a survey with open-ended questions to provide feedback.

Peter West added a new criterion to Conservation Advisory Council member selection: experience in the energy industry. Conservation Advisory Council members expressed support.

3. 2017 Legislative Update

Jay Ward provided an update on the current legislative session.

Jay Ward: Energy Trust doesn't lobby or take positions on legislation, but we do monitor and report on legislative issues. This legislative session, we've monitored about 100 bills that may impact us. Nine bills dealt with the public purpose charge.

Holly Braun: What was most startling or surprising to you?
Jay Ward: It's common to see bills about increased oversight of Energy Trust.

Brent Barclay: Is anything related to code advancing in the process?
Jay Ward: The governor may have an interest in administrative code changes, but it's not in rulemaking.

4. Existing Buildings Pay for Performance offering
Kathleen Belkhayat provided an update on Pay for Performance.

Kathleen Belkhayat: One unique aspect of this program, unlike Strategic Energy Management, is that the customer is working directly with a contractor for performing the operations and maintenance and capital measures. Contrary to our other programs, where we are using engineering estimates for savings, we are looking at what was achieved at the end of the year. For the customer, it's an opportunity to be hands off or as involved as they want. The pilot customer is very happy with the level of service and savings.

Holly Braun: Who was the manager for this project?
Kathleen Belkhayat: It was internally managed. We looked at existing conditions and in some cases used code as a baseline. Pulling the measures apart is complicated. We are looking at how we handle this by backing out the savings.
Oliver Kesting: This is the remaining piece we need to pin down before launching the program.

Kathleen: Pay for Performance allies will work with customers through this program and will receive training. We'll start with retail, office and grocery customers

JP Batmale: What's the Program Management Contractor role? Does the PMC coordinate allies' outreach?
Kathleen Belkhayat: There's a little bit of outreach from the PMC on this offering as initial work in the market. The PMC will mostly review energy reduction plans and qualify and train Pay for Performance allies. They are helping do engineering review and program design.

Stan Price: I'm interested in talking more about the baseline issue. Maybe offline.

Holly Braun: Are you connecting with the city's scoring mechanism to find the right buildings?
Kathleen Belkhayat: That could be a future strategy.

Jess Kincaid: What's the threshold for delayed payment. How long are customers willing to wait for payment?
Kathleen Belkhayat: Seattle City Light got some customer input about this through a workshop. There were some questions about the length of the contract. It's not an issue after the first year.

Charlie Grist: How long is the term? Is it monitored over the full course of the three years?
Oliver Kesting: It's monitored for three years, and we're assuming a five-year measure life.

Charlie Grist: Was there a baseline discussion?
Oliver Kesting: We have been trying to design the program to use the most accurate information upfront to determine what the baseline should be and deduct any extra savings from the model.

The challenge is if the baseline is code and you're looking at the whole-building level, you'll pay on the additional savings also. We can either deduct it upfront or on the back end. I would like some input from the Conservation Advisory Council members. Do you see value in going the second route and paying for savings we actually see at the whole building level?
Stan Price: Yes. I appreciate the hard work you've put into this. I'm not a huge fan of worrying too much about free ridership. I'm in favor of moving this baseline discussion to after-the-fact, so a project isn't held up with a calculation of what the baseline should be. Having the discussion up front puts a throttle on the program that's supposed to encourage participation so you can learn more. If you are trying to weed it out after the fact instead of screening out good candidates, it's helpful.

JP Batmale: This is what a code building should be.

Charlie Grist: If it has a five-year measure life, it limits the term of the baseline thinking. Lighting is a good example. By limiting the term life cycle, you can decide what's in and what's out. The Regional Technical Forum is using a dual baseline where you have a condition for a while and if lighting needs to be replaced after year one, you make some adjustments. What will happen without the intervention, you don't know. Some look like early replacement of things that would have happened anyway. You can change the operating hours of a grocery store and it adjusts the baseline.

JP Batmale: Is the challenge old equipment that never dies—zombie equipment?
Oliver Kesting: Zombie equipment is the nickname we've given equipment that just keeps running and won't get replaced unless we intervene. That's not the concern as much as equipment they would have replaced in the timeline of the program. How do we deduct that? We've seen more and more challenges as we look at it. One solution would be to take a lower evaluation factor.

Stan Price: One of the screening criteria is that there's no planned significant capital project during that time. This may have more implications during the full-scale program. The risk factor may not be significant.

Don Jones: How long they'll wait for payments depends on the size of the payment. The idea of having a baseline calculation will complicate the process.

Julia Harper: If more than six potential projects are interested, how will you decide?
Kathleen Belkhayat: We'll look at the diversity and geographic locations to get a mix.

Chris Smith (Energy 350): Cost-effectiveness will be used to screen projects out, right? If you look at the full cost and full savings, projects end up not being cost-effective and need to be looked at incrementally. If it passes the screening, doing nothing is a viable option. I would hate to throw out good projects. I like the idea of netting it out in the end with evaluations but not ruining good projects up front.

Charlie Grist: Other programs struggled with building and reviewing models. Are you doing that in house? Have you had similar struggles? Is there room for a third party to help?
Kathleen Belkhayat: ICF's engineering team will review the models. We've developed a performance tracking tool that has a standardized format that should help to make review easier.

Holly Braun: Between this and Strategic Energy Management, how do the incentives compare?

Kathleen Belkhayat: For SEM, we offer $0.04/kwh and $0.40/therm for achieved savings after the first year. We pay for incremental savings each subsequent year. For Pay for Performance, we offer $0.05/kwh (operations and maintenance path), $0.10/kwh (capital path) $0.60/therm (operations and maintenance path) and $1.20/therm (capital path) for achieved savings after the first year. The same rate is paid on maintaining the same level of savings in the second and third year.

Oliver: For operations and maintenance measures, that's a total of 15 cents compared to 4 cents for electric savings. Engineering services and coaching are a big part of costs in SEM. In Pay for Performance, we are paying the 15 cents, but the customer needs to have the contract with and pay the Pay for Performance ally.

5. Residential Trends: Existing and New Homes

Marshall Johnson provided an overview of residential trends and sources of savings, including for New Homes and Existing Homes programs in Oregon and Washington.

Don MacOdrum: What is the difference between trade ally and non-trade ally in gas versus electric?
Marshall Johnsons: We have a lot of contractors who install windows but aren't trade allies. A larger percentage of homes with non-trade ally projects are related to windows installed in homes heated by gas.

Lisa McGarrity: Are you counting electronic ignition savings?
Marshall Johnson: We've decoupled the savings from Fireplace Efficiency savings of the unit from electronic ignition savings. This data includes a small subset of Electronic Igntion units that were in Avista territory prior to offering all measures at the start of 2017.

Charlie Grist: How are you measuring savings from midstream ignitions?
Marshall Johnson: We took an allocation based on 2015 baseline research and collected data to adjust the allocation.

Don MacOdrum: Related to the Savings Within Reach trend, there is a steep increase on the gas side and NW Natural recruitment helped. Were they doing something new?
Marshall Johnson: We expanded Savings Within Reach income eligibility. We also focused on HVAC trade allies participation. HVAC contractors are a good fit to support participation this pathway.

Tony Galluzzo: This suggests the DHP measure is upgrading people from electric heat to addcooling also, but what happens on the gas side?
Lisa McGarrity: Are you taking into account a penalty if customers add air conditioning, or does it net out in the savings from heating.
Marshall Johnson: There's a non-energy credit applied, but we aren't taking a reduction for air conditioning use. In general, air conditioning hours of use is pretty low.

Holly Braun: Why is the lowest HSPF efficiency level showing up in 2016?
Marshall Johnson: We did a pilot in manufactured homes to replace electric furnaces, using lower efficiency units due to space limitations.

Holly Braun: It looked like lower tiers were already transformed. Do we know if that will come up in 2018?

Marshall Johnson: It will in retrofits (aka, conversions) and upgrade incentives. We are encouraging 9.0 or 9.5 Heating Seasonal Performance Factor to replace forced air furnaces and evaluating the discontinuation of heat pump upgrade incentives in 2018.

Peter West: Planning staff will be back to a future Conservation Advisory Council meeting with analysis results for some of these measures.

Charlie Grist: Is there an upgrade and conversion program?
Marshall Johnson: Yes, we have both, but the conversion is what we'll set our sights on. There's a bigger savings opportunity.

John Frankel: You show 4,224 EPS new homes. What percentage of the market is that?
Marshall Johnson: That's 38 percent in Oregon and 34 percent in Washington.

Holly Braun: New Homes was big on the pie chart for gas savings. Market transformation is a big part of that. Is that from the baseline moving up in furnaces?
Marshall Johnson: That is from changes to the new construction code, not furnace market transformation.

Charlie Grist: It's great to see year-over-year trends. It's helpful and I want to encourage it. Is there full market data on EPS new homes? Also, aerator savings are big. Have you evaluated them?
Marshall Johnson: We have a sense of the composition of measures that get recognized and a sense of the water heating breakdown in EPS, along with a decent sense that non-efficient water heating is going into code homes. Tankless water heaters are going in new homes on the gas side. We've done some evaluation work on aerators. We have a good sense of how often they get installed and it will be updating other elements in 2018 to align with assumptions from the Regional Technical Forum.
Alan Meyer: We did a study on flow rates.
Marshall Johnson: We did a study on flow rates for multifamily buildings, as well as install rates from Energy Saver Kits. Bathroom aerators and showerheads had the same installation rate and kitchen ones had the worst rates.

6. Updates on Portland's Home Energy Scoring Ordinance
Andria Jacob and Andrew Shepard provided information about the City of Portland's Home Energy Scoring ordinance.

Andrew Shepard: Energy Trust helped train trade allies to deliver Home Energy Scores, and also raised customer awareness. We participate in the Oregon Department of Energy-led HB 2801 group. We hosted additional stakeholder meetings to discuss scoring. EPS for existing homes will no longer be offered by mid-2017. Earth Advantage will use the U.S. Department of Energy Home Energy Score that will be available for homeowners. EPS for new homes will remain as an offering.

Andria Jacob: City council adopted an ordinance last December. It stems from our work on climate action and protection. The national carbon emissions trend is much higher than ours and we are trending downward. Our goal is to reduce emissions by 80 percent by 2050. We are currently at 21 percent despite the growth in population. Owner occupied single-family homes are the starting point as the largest chunk of the housing market.

We are used to seeing informational labels on many things, but not on homes. Single-family homes sold in Portland will receive a score and report. The sellers or builders are the regulated parties. We are the first to require this at the point of listing. We won't publish scores on Portland maps, but realtors will have to scores to regional multiple listing service listings. The draft scorecard is out for review and public comment.

Jess Kincaid: Has any effort been made to have instant-savings measures installed when existing homes are scored?
Andrew Shepard: That's a great suggestion. We've looked into that. We would like to empower real estate professionals to help or order kits.

Holly Braun: This is awesome to see the progression. Realtors weren't in favor of this. Who will enforce scores being entered into RMLS? Is there an exemption for low-income customers? What is the qualification process?
Andria Jacob: The realtors lost the debate, but they could challenge it in court. There were a number of them in support of this. We promised to go back 30 months after implementation, and compliance rates are part of it. We would like to rely on training and education. People will start to do it over time. Earth Advantage will be our quality assurance partner and implementer.

To get around the administrative burden of qualifying people, we specified programs that already do it. If sellers are qualified for Low Income Home Energy Assistance Program or reduced-cost lunches at school, for example, we will take people's word for it. Code does give us the ability to levy fines, but that will come later. Rulemaking will happen in July and August.

Lisa McGarrity: Will there be an exemption processes? Who will pay for it if there's no money?
Andria Jacob: Low-income customers will be exempted, including households who make less than 60 percent of the median income.

Garrett Harris: Will the city coordinate with Energy Trust to track leads and closed transactions for trade allies?
Andrew Shepard: Some of the upgrades are outside of what we can track and quantify. We will track on what we can.
Andria Jacob: We have an evaluation contractor who goes over and above energy savings.
Tony Galluzo: It sounds like an assessment similar to what an allied technical assistance contractor would provide. Is this for all utilities?
Andria Jacob: They are trained and licensed providers. The market driven cost is about $200 to $250.
Roger Kainu: I was just at conference where this came up. Nationally, it looks like the prices are coming down to more like $100. Home inspectors can give scores while they are doing their inspections.

7. Energy Trust's diversity, equity and inclusion strategy

Debbie Menashe provided an update on the current status of Energy Trust's Diversity Initiative strategies and community outreach efforts. She shared the mission statement and initiative standards, objectives and goals to bring cultural competency to both the organization and its programs and projects. The purpose of the mission is to better serve diverse populations, contractors and partners. Debbie asked for assistance to convene a group of clean energy organizations to identify the jobs that are available now and in the future in order to better recruit diverse populations.

Lisa: Will you use a third party to help with data analysis?
Debbie: We do that often. We also need help understanding cultural concerns and history.

Andria Jacon: The Clean Energy Works Portland pilot proved that it's difficult and tricky to work with diverse customers. It's not easy, but great to see. We had an external party do an equity audit to understand who benefits from or is harmed by these policies and actions. When we engaged with groups, we heard feedback that it was the city's priority, not theirs.

Don Jones: Have you considered asking other organizations that are out ahead of you on these things?
Debbie Menashe: Yes. We don't cover the low-income community, but we are focused on reaching everyone.

Jess Kincaid: Reach out to the educational system. Community colleges, colleges and universities are trying to support equity.
Debbie Menashe: Mount Hood Community College had a career fair about ten days ago and we attended.

Don MacOdrum: How deep back into the pipeline are you looking? A lot of people are starting to make decisions about their careers in school that will impact the rest of their lives.
Debbie Menashe: We are working with DeLaSalle High School for interns who have been with us all year. We hope that they remember when they move on.

Allison Spector: It's good to look at the educational institutions and why women and people of color are not in certain fields. Are there champions that keep them interested and engaged? Can you support that?

Charlie Grist: This came up in the seventh power plan. Ways to look at data to see where we are touching and not. There is a coalition of 10 utilities or so that are trying to produce some ways to measure by the end of this year. NEEA is participating.

Roger Kainu: Oregon Worksource puts on a presentation about equity gentrification. He can point out where the pockets are within Oregon with the highest concentrations of different groups.

8. Planning 2017 Conservation Advisory Council agendas
Peter West asked what topics should come to Conservation Advisory Council meetings in 2017.

Peter West: What is missing? Sector trends analysis will become part of the upcoming budget process. Penetration analyses will show results of deep reaching into markets. We will present ductless heat pump analyses will come back in about August or September.

JP Batmale: How about a status report on the new residential PMC selection and process?
Peter West: Selection will be presented in September, and status updates will provided in 2018.
Andria Jacob: When will the decision be made?
Peter West: It will go to the board on July 26.
Alan Meyer: You can be fairly confident that the recommendation will go through.

JP Batmale: Do we ever hear what comes out of the board strategic planning workshop?
Alan Meyer: The information will be available following the next board meeting.

Don MacOdrum: Selection and notification of respondents happens on June 26. Would that be public?
Peter West: The selection will be approved and publicly available at the July 26 board meeting.

9. Public comment
Dave Bamford: The diversity study is very progressive, and I would love to see scoring become the national model. It can become a great selling tool for realtors.

10. Meeting adjournment
The next scheduled meeting of the Conservation Advisory Council will be on June 21, 2017 at 1:30 p.m.

Retail Lighting Strategy Update

Conservation Advisory Council

June 21, 2017

Energy Trust of Oregon

Findings from Bonneville Power Administration

Residential Lighting

Understanding the past and looking into the future

Bonneville
POWER ADMINISTRATION

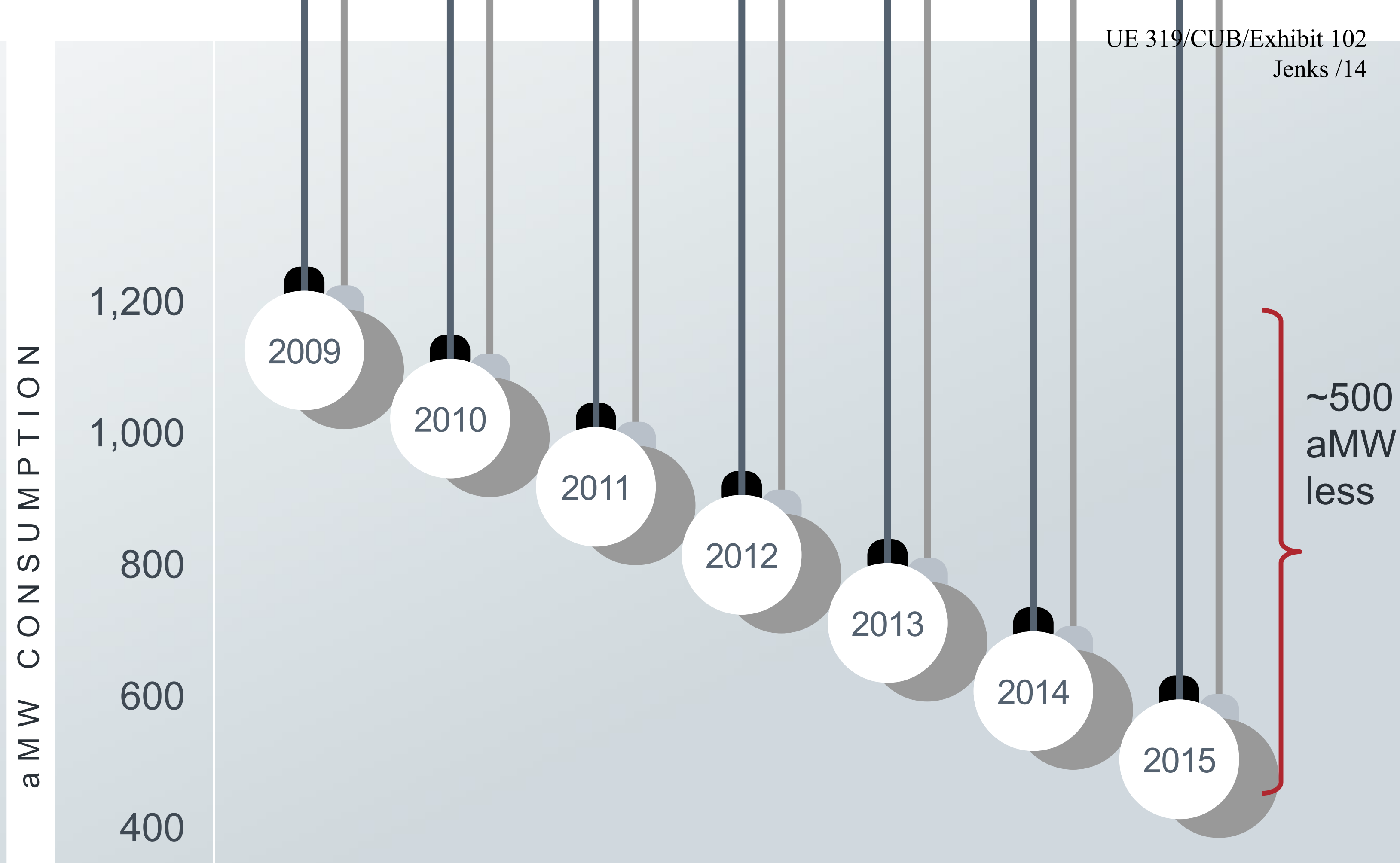
By the numbers

More than
300 million
lamps in NW homes

3rd largest
residential end-use

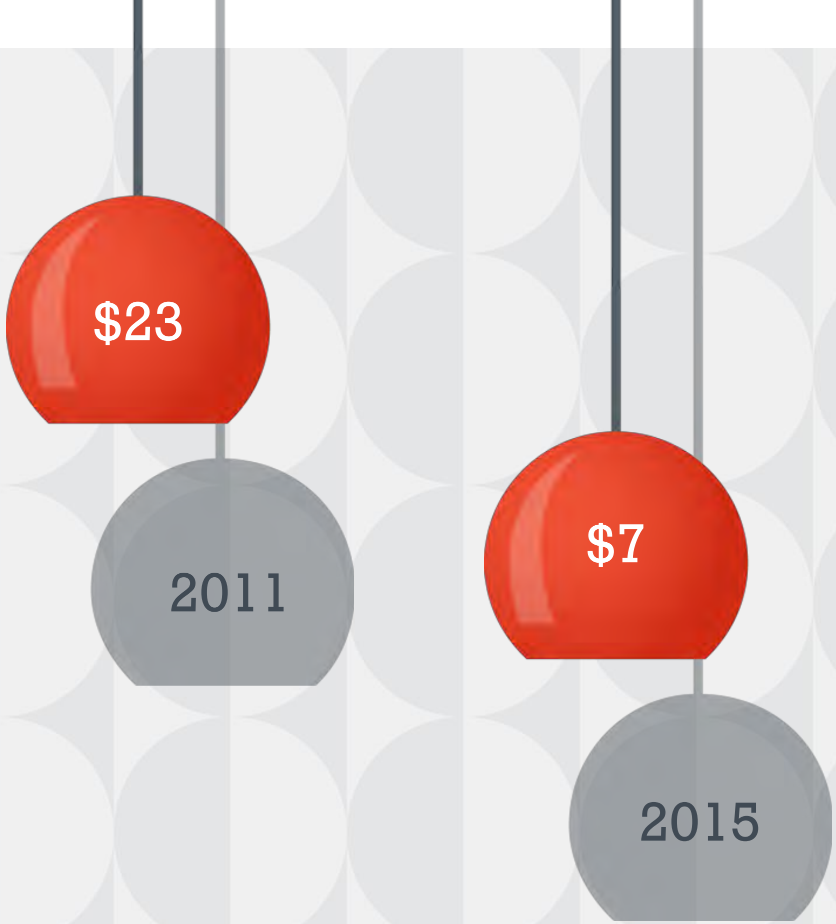
Approximately
6%
of total regional energy use (all sectors)

More than
25%
of the region's residential program energy and demand savings



39% decline in lighting consumption

What caused the drop?

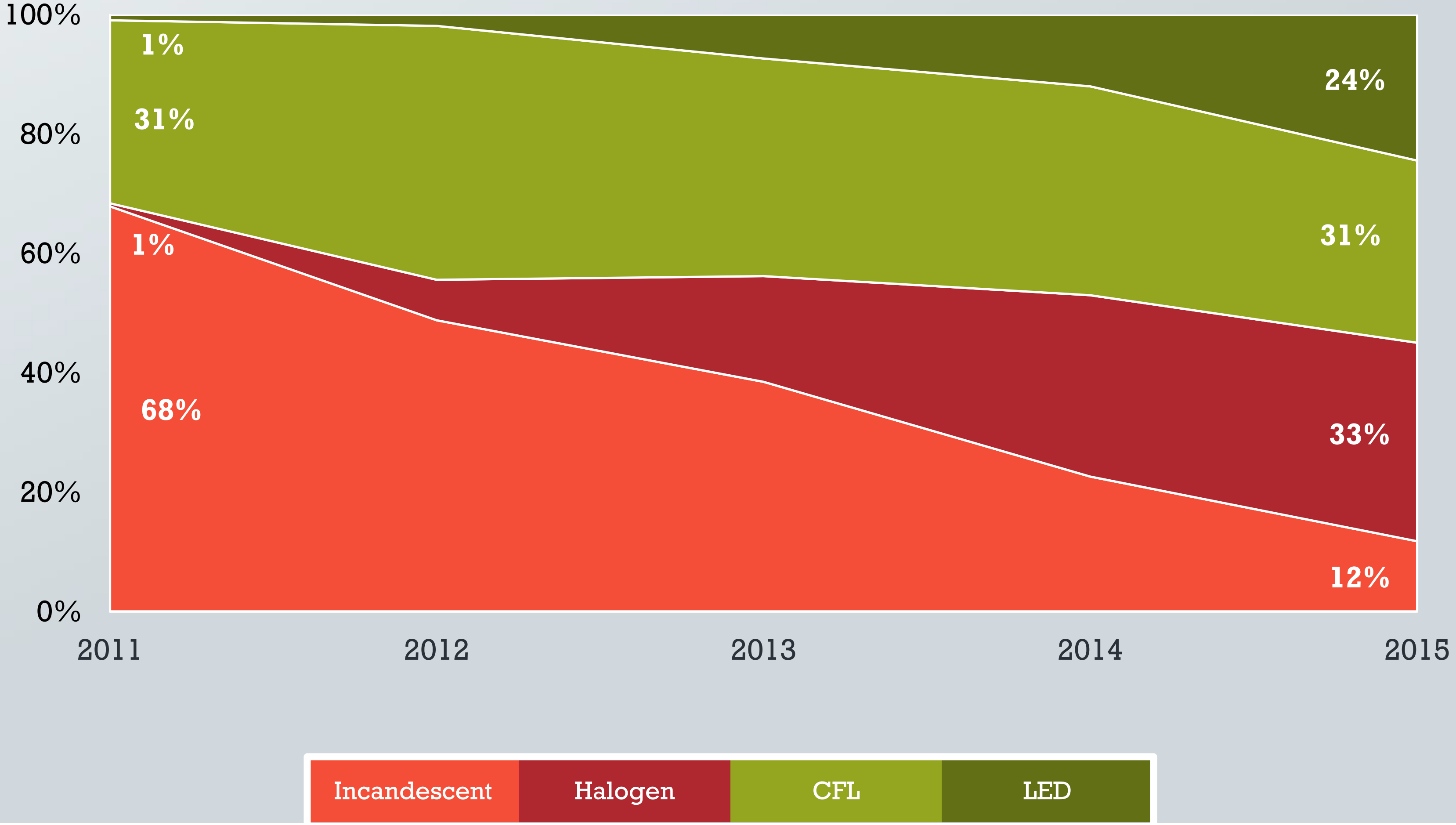


Less Expensive LEDs

Average Cost of a Typical General Service Lamp

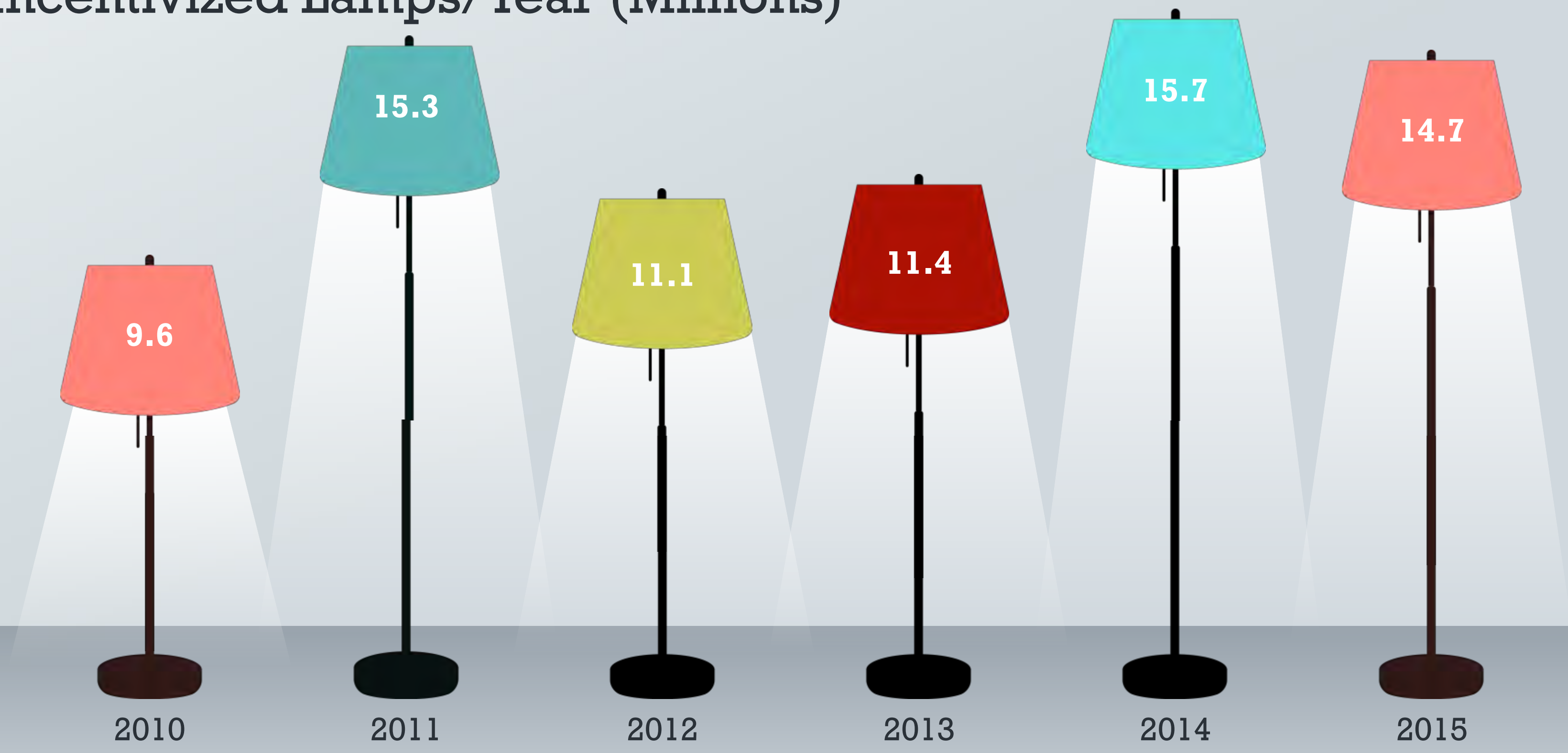
EISA came into effect

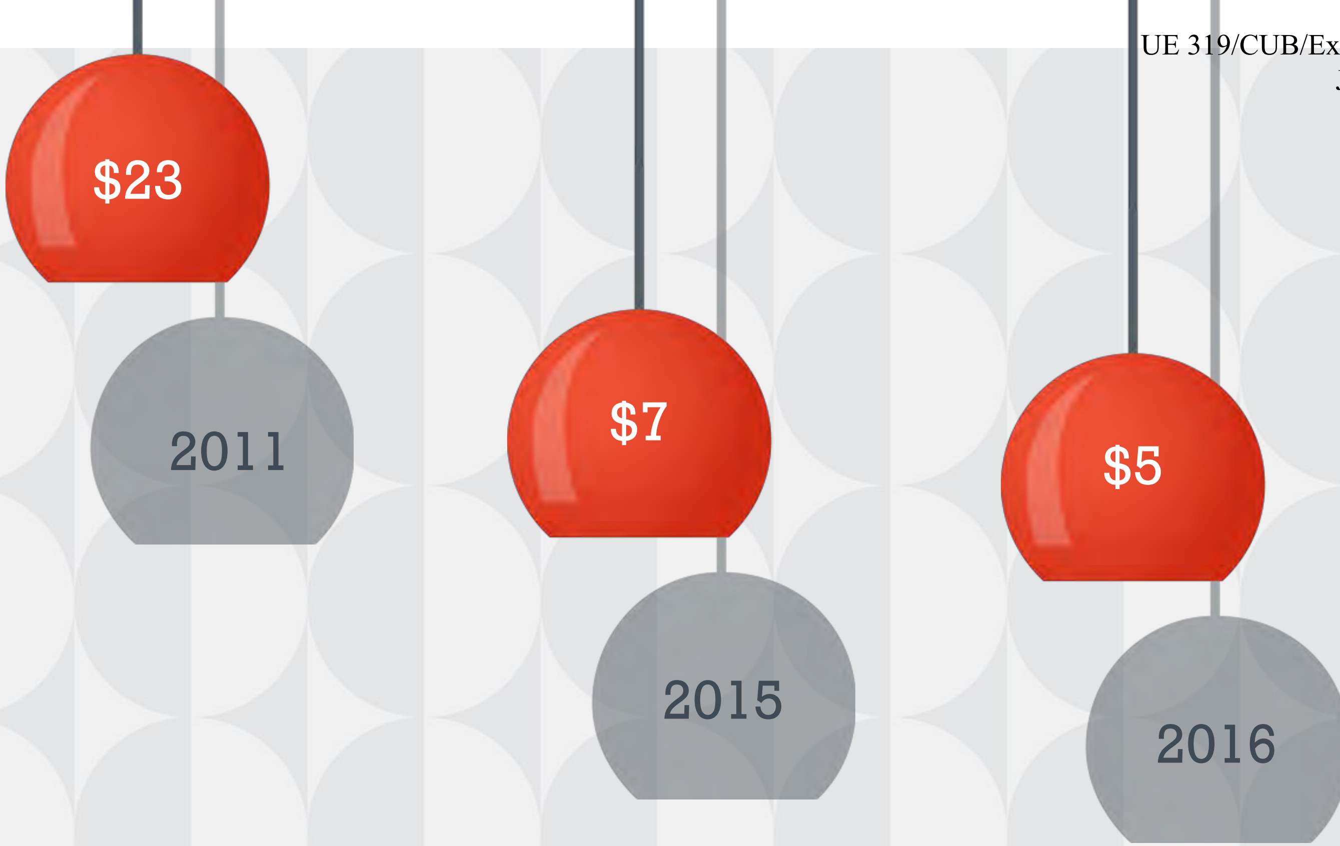
General Service Lamps Market Share



Persistent region-wide utility programs

Incentivized Lamps/Year (Millions)



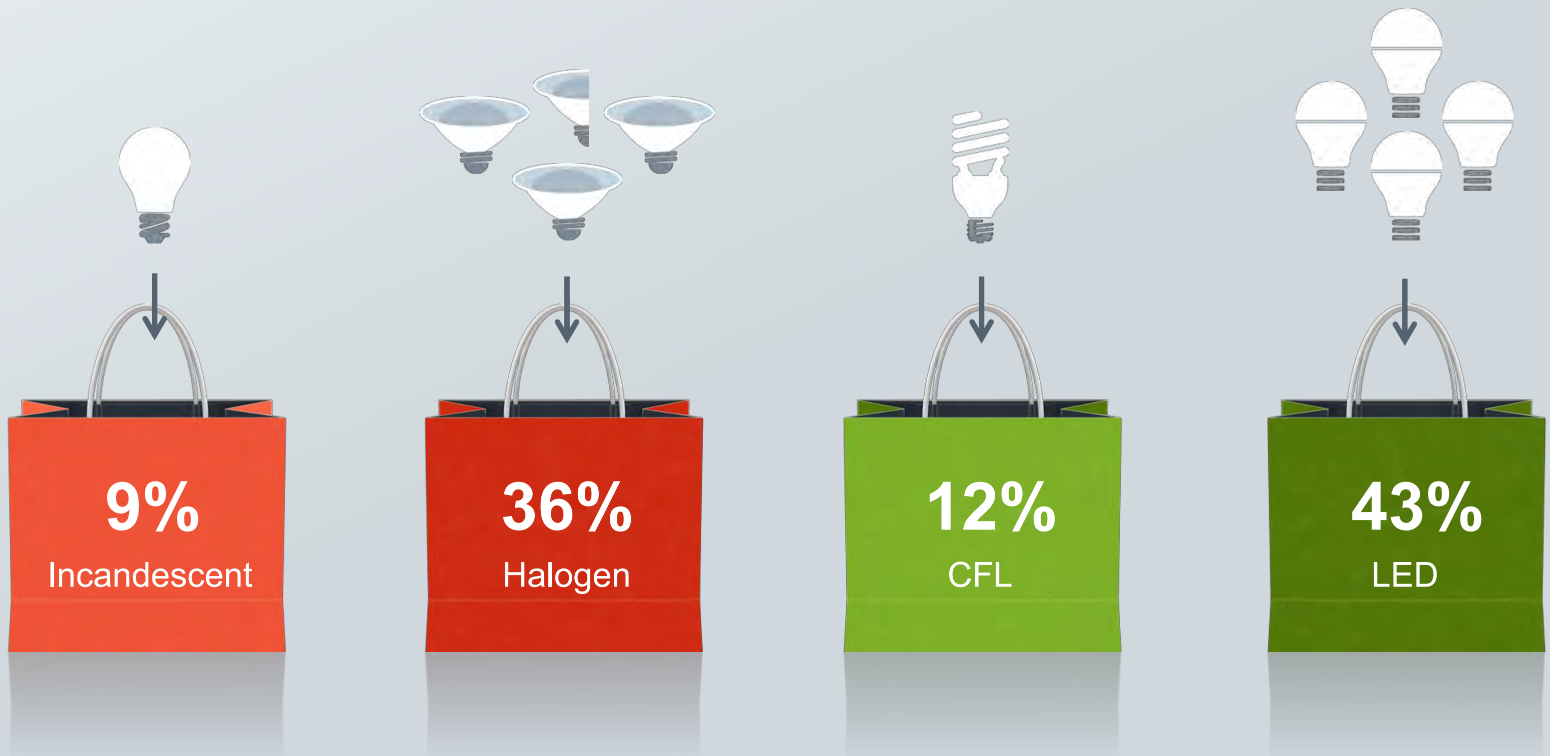


LED Prices Continue to Decline

Average Cost of a Typical A-Type Lamp

Data provided by neea

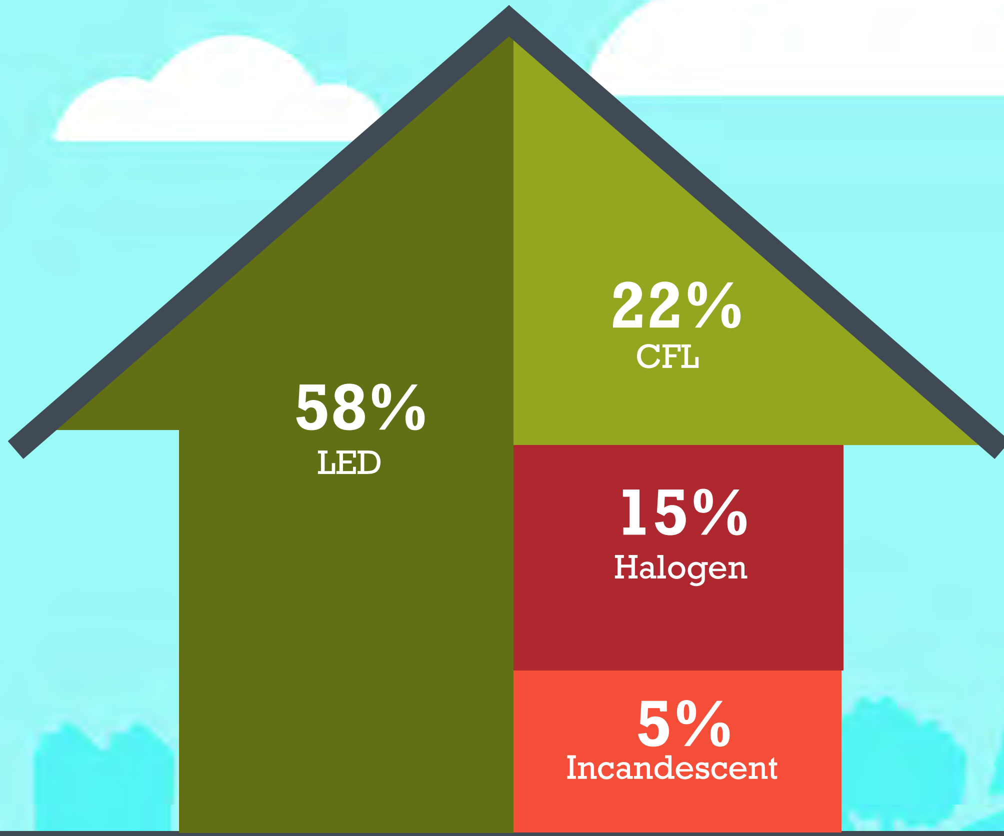
LEDs were the top seller in 2016



Data provided by neea

Looking ahead

LEDs will be 58% of lighting stock by 2020



Energy Trust
Retail Lighting Update

Retail Lighting Market Landscape

- Quickly changing
- Complex
- High volume

Decision-making Framework

1. Track LED market share

2. Characterize max market-share indication point

3. Track incremental cost

4. Adaptive measure approval and budget management

5. Improve industry stakeholder engagement

Data Sources

- Nielsen Sales Data
- Residential Building Stock Assessment (NEEA)
- Retail Lighting Market Tracking (NEEA)
- PMC Shelf Surveys

Goals

- Achieve available cost-effective savings
- Minimize over-incentivizing and free-ridership
- Avoid prematurely exiting the market
- Allow for flexibility and innovative program design
- Grow relationships with retailers, manufacturers and other market actors

Thank You

Ryan Crews
Residential Program Manager

Energy Trust of Oregon

Cannabis Market Update

Conservation Advisory Council

June 21, 2017

Overview and History

- Energy Trust began serving medical facilities in May 2013; adult-use/recreational began in 2016
- 2013 to 2015: incentives provided to 12 medical cannabis projects; about 800,000 kWh in savings
- 2016: incentives provided to 15 cannabis sites; about 1 million kWh in savings
- 2017: expect savings to exceed 4 million kWh
- Outreach strategy

Baselines

Baseline lighting is 1,000 watt HPS; some fluorescent

Baseline HVAC is standard eff. heat pump or mini-split

Baseline loads are 80-100 watts per square foot

Typical lighting hours

- Vegetative - 18 hours/day, 7 days per week
- Flowering - 12 hours/day, 7 days per week

Opportunity: Lighting, HVAC, Other

HVAC

- Three coil systems – cooling and dehumidification
- Variable refrigerant flow (VRF)
- Water cooled chillers and water side economization

Lighting: LED, ceramic, plasma

Dehumidification

Odor control – Plasma ionization air filtration

Savings of 25-50% currently feasible

Challenges

- Cultural – Growers know what works
- New players – Investors interested in bottom line
- Technological knowledge
- Competing priorities – Permitting, power, product
- Awareness of programs; building trust
- Learning with the market

INCENTIVES FOR CANNABIS CULTIVATION

GREENHOUSE REBATES AVAILABLE

- Infrared, IR, polyethylene greenhouse covers
- Greenhouse controllers
- Condensing unit heaters
- Under-bench heating equipment
- Thermal curtains

Cultivation of medical and adult use cannabis can be energy intensive. Energy Trust of Oregon offers licensed growers free technical services and cash incentives for the installation of energy-efficient equipment at new and existing grow facilities.

Custom energy solutions

Energy Trust can work with cannabis producers to identify and implement custom improvements that can reduce energy costs over conventional equipment.

Energy Trust offers free technical services and provides cash incentives for:

- High-efficiency lighting and lighting controls, including LEDs. Energy Trust lighting specialists can work with you or your lighting vendor to specify qualified equipment.
- Technical studies to identify energy-efficiency opportunities for HVAC, insulation and other improvements, for qualified projects. Energy Trust pays 100 percent of the study cost.

Cash incentives are based on estimated annual energy savings and are available at $0.25 per kilowatt hour saved and $2.00 per therm saved.* Incentives can cover up to 50 percent of your upfront project cost and can be provided directly to the equipment vendor or contractor, reducing your investment. All custom projects must be pre-approved by Energy Trust to be eligible for incentive payments.

Eligibility requirements

- Your business must be licensed by the State of Oregon and be on the active business registry.
- Energy-efficiency measures must be installed in a permanent structure. Trailers or moveable structures are not eligible for incentives.
- The project site must be located in Oregon and served by Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas, or Avista on a qualifying rate schedule.
- Energy Trust must conduct pre- and post-verification for the installation.
- Additional eligibility requirements may apply and could vary depending on your project.

Incentives are subject to availability and may change.

+

Get more from your energy.
To learn more about additional rebates and cash incentives available for your project, visit **www.energytrust.org/grow** or call **1.866.202.0576**.

Energy Trust of Oregon
421 SW Oak St., Suite 300
Portland, OR 97204
1.866.202.0576 **energytrust.org**

Serving customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista. 1/17

EnergyTrust of Oregon

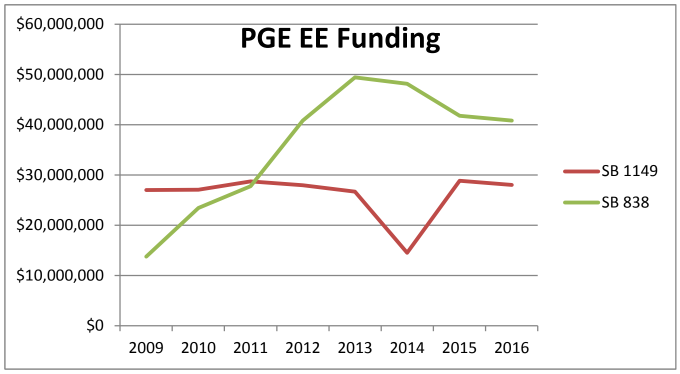
Thank You

Sam Walker

Sr. Program Manager,
Industry and Agriculture

year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
SB 1149	$26,968,799	$27,068,050	$28,698,128	$27,971,825	$26,647,957	$14,478,751	$28,833,564	$28,025,055		
SB 838	$13,766,914	$23,397,922	$27,775,063	$40,795,172	$49,402,929	$48,160,176	$41,780,430	$40,830,439		

source of SB 1149 2009-2016: CUB Exhibit 1xx OPUC DR 402-A
source of SB 838 2009- 2016: CUB Exhibit 1xx OPUC DR 402-B



incentives to invest and (3) fix the broken system, allowing all available energy efficiency to be achieved.

In the following section, CUB will demonstrate its new methodology and the results obtained there from and will then demonstrate how this new approach to the marginal cost study improves accuracy, provides proper economic incentives and fixes the broken system as noted above.

C. Including EE In The Marginal Cost Of Service Study

i. Methodology

The first step to creating a new marginal cost methodology is to identify the failures of the original model, and how those failures created inaccuracies and inconsistencies. CUB recognizes that PGE serves customers with embedded resources, not marginal resources, and that the marginal cost study is a theoretical approach designed to properly align the incentives of the Company while efficiently serving ratepayers. That said, CUB also understands that the marginal cost study is intended to be long run in nature[52]- in line with the IRP- and believes that it should be as accurate as practicable.

The Company models marginal costs from a mix of only traditional resources (SCCT and CCCT). However, both the Oregon RPS standards require the company to produce a minimum of 25% of its energy with renewable resources. Moreover, the PGE IRP clearly identifies EE as an integral resource.[53] CUB finds this approach inconsistent, and detrimental to implementing accurate EE investment price signals.

[52] UE 283 PGE/1400/Cody/3, lines 1-4.
[53] PGE 2013 IRP pg 57, table 4 and IRP appendix B.

Instead, CUB identifies the ratios in the Company's 2025 projection of the cumulative new resources:

Table 5: Projected Cumulative New Resources[54]

Resource	mWa	IRP
Baseload Gas	653	50.54%
Wind	280	21.67%
EE	259	20.05%
procurement	100	7.74%
total	**1292**	**100.00%**

This represents the long-run marginal electric resource. In a marginal cost study, we calculate customer loads as if there were no embedded resources and loads were served solely by marginal resources. CUB then creates a theoretical resource mix that is consistent with the Company's marginal resource (SCCT and CCCT) serving 50.54% of the load.[55] Then, we calculate EE resources as 20.05% of the total theoretical resource needs.[56] These are the total EE investments consistent with the level of traditional resources in the current Company's marginal cost study, assuming a resource portfolio that is in line with the IRP. Then, CUB calculates the amount of EE in the resource mix that each schedule pays for under the current funding levels.[57]

[54] PGE 2013 IRP pg 57 and IRP appendix B page B2 "Baseload/Gas RPS Only." CUB chose this because PGE identified this portfolio as the preferred portfolio in the 2013 IRP.
[55] We set 50.54% of the total load equal to COS Calendar Energy 17,663,507 mWh, found in 1400 Workpapers RatespreadGRC15 tab Generation.
[56] CUB Exhibit 103 tab marginal resource mix.
[57] This includes SB 1149 and SB 838 funding.

Table 6: EE Funded By Class As a Marginal Resource[58]

Rate Schedule		
Schedule 7		53.94%
Schedule 15/515		0.21%
Schedule 32/532		10.54%
Schedule 38/538		0.35%
Schedule 47		0.18%
Schedule 49/549		0.48%
Schedule 83/583		15.16%
Schedule 85/485/585		14.75%
Schedule 89/489/589		1.58%
Schedule 90/490/590		1.72%
Schedule 91/95/591/595		1.07%
Schedule 92/592		0.02%
Total net 400 schedules		100.00%

The total amount of EE is then included in the theoretical marginal resource mix. Then, instead of immediately reconciling loads with revenue requirements, CUB first gives each schedule credit for the EE it individually funded and subtracts it from the total scheduled load (gross of EE).

Note the difference from the existing practice. Currently, the Company models Schedule loads from actual usage, indirectly internalizing EE applied to each schedule. This means each customer class is affected by the energy efficiency programs that reduce the load from its class rather than the EE that is funded by its class. In this sense, customers that pay less in ETO funds receive more benefits – those customers benefit doubly. They benefit by enjoying lower system costs at the expense of other ratepayers who are funding their EE, they benefit by experiencing reduced loads which also means they are shouldering smaller load portions of system costs.

[58] CUB Exhibit 103 tab 2015 EE.

CUB's approach improves the marginal cost modeling. In CUB's marginal cost approach, CUB models Schedule loads as the actual portion of system resources, then accounts for conservation funded. This gives credit where credit is due, and removes double counting. Now each individual load is net of EE, as it needs to be, to calculate percentage load for each schedule, and reconcile revenue requirement with forecasted load.

Table 7: Calculating the Load Net of EE[59]

Schedules		Energy Percent per PGE	System mWa allocation gross ETO	EE mWa	system mWa Allocation net ETO	mWa of traditional energy gen
Schedule 7		43.03%	1716.86	431.41	1,285	40.30%
Schedule 15		0.08%	3.22	1.64	2	0.05%
Schedule 32		8.83%	352.17	84.33	268	8.40%
Schedule 38		0.25%	10.17	2.82	7	0.23%
Schedule 47		0.11%	4.26	1.44	3	0.09%
Schedule 49		0.40%	15.94	3.82	12	0.38%
Schedule 83		15.64%	623.98	121.28	503	15.76%
Schedule 85		17.26%	688.46	117.95	571	17.89%
Schedule 89 GT4MW		5.99%	239.16	12.65	227	7.10%
Schedule 90		7.90%	315.01	13.77	301	9.44%
Schedule 91/95		0.49%	19.58	8.52	11	0.35%
Schedule 92		0.02%	0.72	0.13	1	0.02%
TOTAL		100%	3,990	800	3,190	100.00%

ii. Results Under CUB's Methodology

Having determined the new load ratios CUB next reconciles these new load ratios with the Company's revenue requirement, and calculates the revenue share of marginal energy costs per Schedule.

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[59] CUB Exhibit 103 tab model.

Table 8: Marginal Energy Costs[60]

		CUB	PGE
Schedules		Marginal Energy Costs	Marginal Energy Costs
Schedule 7		$393,157.37	$419,840,573
Schedule 15		$483.64	$787,636
Schedule 32		$81,920.00	$86,120,231
Schedule 38		$2,247.14	$2,486,765
Schedule 47		$863.24	$1,042,147
Schedule 49		$3,706.28	$3,897,406
Schedule 83		$153,751.41	$152,587,547
Schedule 85		$174,492.40	$168,355,667
Schedule 89 GT 4 MW		$69,277.36	$58,482,927
Schedule 90		$92,136.62	$77,032,786
Schedule 91/95		$3,382.35	$4,788,047
Schedule 92		$180.65	$176,735
TOTAL		$975,598,466	$975,598,466

CUB then adds the additional costs for distribution, transmission, customer service and other charges,[61] to discover how this marginal cost methodology changed PGE's allocated costs.

[60] CUB Exhibit 103 tab model.
[61] UE 283 PGE/1404/Cody/1-2.

Table 9: Change in Cost Allocation[62]

Schedule	PGE Power Supply	CUB Power supply	CUB Cost Allocation	PGE Allocation	Schedule Change From PGE 2015
7	$419,841	$393,157	$853,269	$879,952	-3.03%
15	$788	$484	$3,447	$3,751	-8.11%
32	$86,120	$81,920	$163,985	$168,185	-2.50%
38	$2,487	$2,247	$5,475	$5,715	-4.20%
47	$1,042	$863	$4,867	$5,046	-3.54%
49	$3,897	$3,706	$15,644	$15,835	-1.21%
83	$152,588	$153,751	$237,086	$235,923	0.49%
85	$168,356	$174,492	$244,969	$238,833	2.57%
89	$58,483	$69,277	$86,700	$75,906	14.22%
90	$77,033	$92,137	$99,351	$84,247	17.93%
91&95	$4,788	$3,382	$15,855	$17,260	-8.14%
92	$177	$181	$251	$247	1.68%
total	$975,598	$975,598	$1,730,900	$1,730,900	0.00%

The results show exactly what one would expect. The customer classes that are purchasing additional EE through SB 838 show their costs going down once those classes are credited for the amount of EE they are purchasing. The classes that have avoided paying for EE find their costs going up once they no longer are getting credit for the amount of EE being purchased by other classes of customers.

D. Potential Variable: Apply Methodology to SB 838 Only

CUB's analysis was based on accounting for EE from both SB 1149 and SB 838 in the marginal cost study. From a theoretical marginal cost basis, there is no reason not to account for both of these funding sources. However, CUB recognizes that large customers are not prohibited from receiving a direct benefit from the SB 1149 programs

[62] CUB Exhibit 103 tab results.

and the requirement that these funds be collected across all charges, including distribution, is part of the law. Therefore, CUB recognizes that one variation on our approach could be to include EE in the marginal cost study but to limit that to the SB 838 EE funds. This will reduce the impact of our proposed marginal cost methodology change.

E. Customer Impact Offset

It is important to recognize that CUB is not proposing that rates be rebalanced to the full extent shown here all at one time. The imbalance shown in CUB's charts grew over time since the passage of SB 1149 and the creation of the ETO.I Given this fact, it would not, therefore, be unreasonable to spread the correction of the imbalance over an equal amount of time.

CUB notes that PGE's rate spread includes a Customer Impact Offset ("CIO") which PGE has designed to prevent any customer class from seeing an increase greater than 12%. The CIO could also be used to reduce the impact of implementing this change in marginal cost methodology. This could be done by adjusting the number for the overall rate hike ceiling from 12% to whatever is believed to be reasonable. Or, a second component of the CIO could be implemented that would phase in this marginal cost adjustment by only implementing a certain percentage of it (10%, 25%, 50%).

V. Overcoming the Cap on Industrial EE

A. PGE Is Reaching Its Current Cap On Industrial EE Programs And Will Soon Be Leaving Industrial EE On The Table.

Even if each schedule appropriately gets load credit for that which they funded, larger customers will continue to receive a larger portion of programmatic funds from the

ETO, simply because large conservation projects tend to be more cost effective. CUB's marginal cost approach does not attempt to undo or change the practices of the ETO. The ETO's programmatic decisions and their savings per dollar results speak volumes for themselves. However, without a new approach at marginal cost, the ETO is in very real danger of not being able to do its job because it will be unable to continue its industrial and commercial EE programs. And, the State of Oregon will be in very real danger of losing conservation projects at the expense of more expensive, higher carbon energy resources. And all this is because under the current legal interpretation, PGE's industrial customers will very soon be restricted from receiving additional industrial EE programs because of the "direct benefit" cap in SB 838. This will mean that PGE's system will no longer be purchasing all the cost effective EE that is in actuality available.

B. The Direct Benefit Test Is Misplaced.

The primary benefit of EE programs is not the receiving of incentives to implement cost effective measures, but the benefits brought by the lower costs associated with the purchase of EE as opposed to other sources of power. The reason we purchase EE is because it is the least cost/least risk resource and because it reduces costs to the system. Not only is it less expensive than supply-side resources, by reducing loads, EE stretches out our hydro base over a wider percentage of load. EE does not need transmission and EE is not subject to line losses. The direct benefit to all customers (industrial and non-industrial alike) is the lower cost associated with energy efficiency. For this reason, it is CUB's position that if the Commission recognized that the direct benefit of EE is lower power costs, and not the receiving of incentive payments, then the proper way to implement the SB 838 cap would be to place the cap on the receipt of direct benefits and not on the receipt of incentive payments through EE programs aimed at a customer class. This could be done by implementing the marginal cost/cost allocation approach advocated for by CUB. A marginal cost study that takes into account the source of the EE funding that is paying for the direct EE benefits and then directs the allocation of those direct benefits to the funding source. So if residential customers were to purchase all the EE including industrial EE but the benefits of this lower cost resource were also to flow to residential customers and not to the industrial customers, then everyone would be operating within the spirit and letter of the law and EE could still be purchased to its fullest extent.

In summary, residential and small commercial ratepayers do not need to be protected from other customer classes receiving EE programs so long as all EE that residential and small commercial customers are purchasing (whether residential, industrial or commercial) is credited directly to the residential and small commercial customers and not to the other classes. This fulfills the purpose behind the protections intended to be provided by SB 838 to small customers when it said that while industrial customers would not be paying for more EE, they could not receive any direct benefits. And under this approach, there is no reason for residential, small commercial, or any other class of customers to oppose the funding of industrial energy efficiency programs with their dollars because those classes will be obtaining credit for all the EE they purchase.

Schedule	PGE Power Supply	CUB Power supply	CUB Cost Allocation	PGE Allocation	Schedule Change From PGE 2015
7	$419,841	$393,157	$853,269	$879,952	-3.03%
15	$788	$484	$3,447	$3,751	-8.11%
32	$86,120	$81,920	$163,985	$168,185	-2.50%
38	$2,487	$2,247	$5,475	$5,715	-4.20%
47	$1,042	$863	$4,867	$5,046	-3.54%
49	$3,897	$3,706	$15,644	$15,835	-1.21%
83	$152,588	$153,751	$237,086	$235,923	0.49%
85	$168,356	$174,492	$244,969	$238,833	2.57%
89	$58,483	$69,277	$86,700	$75,906	14.22%
90	$77,033	$92,137	$99,351	$84,247	17.93%
91&95	$4,788	$3,382	$15,855	$17,260	-8.14%
92	$177	$181	$251	$247	1.68%
total	$975,598	$975,598	$1,730,900	$1,730,900	0.00%

Rate Schedule	NET EE marginal energy cost	Net EE Marginal Energy Costs ($000)	per PGE Generation Capacity Allocation	per PGE Marginal Capacity Costs	per PGE Marginal Capacity Costs ($000)	Net EE marginal energy and capacity costs	Net EE marginal energy&capacity percent	allocated revenue requirement		Comparison CUB proposal	PGE proposal	% change
Schedule 7	$393,157,373.98	$393,157.37	50.61%	$167,981,029.35	$167,981.03	$561,138.40	42.92%	$444,462.14		$444,462.14	465,597.16	-4.54%
Schedule 15/515	$483,638.88	$483.64	0.06%	$212,223.55	$212.22	$695.86	0.05%	$551.17		$551.17	791.96	-30.40%
Schedule 32/532	$81,919,999.19	$81,920.00	8.55%	$28,375,583.53	$28,375.58	$110,295.58	8.44%	$87,362.07		$87,362.07	90,688.95	-3.67%
Schedule 38/538	$2,247,141.21	$2,247.14	0.21%	$708,223.96	$708.22	$2,955.37	0.23%	$2,340.86		$2,340.86	2,530.66	-7.50%
Schedule 47	$863,240.20	$863.24	0.19%	$625,129.79	$625.13	$1,488.37	0.11%	$1,178.90		$1,178.90	1,320.60	-10.73%
Schedule 49/549	$3,706,278.42	$3,706.28	0.63%	$2,084,484.05	$2,084.48	$5,790.76	0.44%	$4,586.70		$4,586.70	4,738.09	-3.20%
Schedule 83/583	$153,751,409.92	$153,751.41	14.57%	$48,350,371.63	$48,350.37	$202,101.78	15.46%	$160,079.21		$160,079.21	159,157.34	0.58%
Schedule 85/485/585	$174,492,398.62	$174,492.40	14.86%	$49,312,468.81	$49,312.47	$223,804.87	17.12%	$177,269.62		$177,269.62	172,408.88	2.82%
Schedule 89/489/589	$69,277,359.07	$69,277.36	4.36%	$14,469,619.51	$14,469.62	$83,746.98	6.41%	$66,333.66		$66,333.66	57,783.69	14.80%
Schedule 90/490/590	$92,136,620.70	$92,136.62	5.56%	$18,462,730.59	$18,462.73	$110,599.35	8.46%	$87,602.67		$87,602.67	75,639.35	15.82%
Schedule 91/95/591/595	$3,382,354.64	$3,382.35	0.39%	$1,290,011.42	$1,290.01	$4,672.37	0.36%	$3,700.85		$3,700.85	4,814.26	-23.13%
Schedule 92/592	$180,651.05	$180.65	0.01%	$40,623.82	$40.62	$221.27	0.02%	$175.27		$175.27	172.16	1.80%
Schedule 485	NA											
Schedule 489	NA											
Total net 400 schedules	$975,598,465.89	$975,598.47	100.00%	$331,912,500.00	$331,912.50	$1,307,510.97	100.00%	$1,035,643.12	match	$1,035,643.12	1,035,643.12	
				$975,598,466								
					Target	$1,035,643						

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2015 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	$92,593	$22	$7,514	$1	$1,743	$0	$48,614	$6	$39,358	$5	$189,821	$33		$189,855	$879,952
Schedule 15	$244		$24		$0		$138		$76		$482	$0	$1,997	$2,479	$3,751
Schedule 32	$8,866	$13,961	$259	$168	$201	$130	$3,358	$2,181	$3,083	$2,002	$15,767	$18,443		$34,210	$168,185
Schedule 38	$17	$453	$0	$1	$2	$24	$4	$37	$4	$42	$28	$557		$584	$5,715
Schedule 47	$18	$379	$1	$9	$1	$9	$11	$147	$8	$106	$38	$649		$688	$5,046
Schedule 49	$1	$381	$0	$21	$0	$8	$0	$91	$0	$51	$1	$552		$553	$15,835
Schedule 83															
Secondary	$339	$14,609	$11	$173	$17	$272	$100	$1,570	$130	$2,051	$598	$18,674		$19,272	$235,923
Schedule 85															
Secondary		$3,000		$36		$89		$858		$2,650	$0	$6,631		$6,631	
Primary		$442		$4		$10		$101		$311	$0	$868		$868	$171,140
Schedule 85 1-4 MW															
Secondary		$441		$11		$3		$46		$681	$0	$1,182		$1,182	
Primary		$235		$11		$4		$47		$696	$0	$993		$993	$67,693
Schedule 89 GT 4 MW															
Secondary		$19		$13		$0		$1		$98	$0	$131		$131	
Primary		$146		$349		$0		$14		$2,644	$0	$3,154		$3,154	
Subtransmission		$183		$104		$0		$4		$784	$0	$1,074		$1,074	$75,906
Schedule 90-P		$22		$0		$0		$2		$392	$0	$415		$415	$84,247
Schedules 91 & 95	$1,656			$0		$0	$98		$120		$1,874	$0	$7,796	$9,669	$17,260
Schedule 92		$20		$0		$0		$8		$5	$0	$33		$33	$247
Totals	$103,733	$34,313	$7,809	$900	$1,964	$550	$52,323	$5,111	$42,779	$12,515	$208,609	$53,390	$9,792	$271,791	$1,730,900
													Reconcile to Ratespread		$0.00

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PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2015 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	$466,521	$21,866	$1,463	($585)	$22,743	$16,756	$2,202	$18,958	$35,653	$19,229	$61,660	$65,334	$181,875
Schedule 15	$793	$93	$2	($1)	$95	$24	$4	$28	$78	$42	$140	$95	$356
Schedule 32	$90,623	$4,187	$284	($122)	$4,349	$3,021	$429	$3,450	$6,058	$3,267	$12,063	$14,166	$35,554
Schedule 38	$2,536	$142	$8	($3)	$147	$80	$12	$92	$382	$206	$923	$844	$2,356
Schedule 47	$1,315	$125	$4	($1)	$128	$56	$6	$62	$265	$143	$1,337	$1,108	$2,854
Schedule 49	$4,740	$393	$15	($5)	$403	$191	$22	$214	$1,005	$542	$5,207	$3,172	$9,925
Schedule 83													
Secondary	$158,883	$5,882	$498	($214)	$6,165	$5,221	$753	$5,974	$10,658	$5,748	$18,541	$10,682	$45,629
Schedule 85													
Secondary		$3,978	$416	($3,303)	$1,091								
Primary		$426	$48	($392)	$82								
Class Total	$122,534					$3,973	$587	$4,561	$9,537	$5,144	$14,344	$6,347	$35,373
Schedule 85 1-4 MW													
Secondary		$874	$91	($726)	$239								
Primary		$897	$101	($825)	$173								
Class Total	$50,229					$1,511	$228	$1,739	$3,665	$1,977	$5,715	$1,781	$13,138
Schedule 89 GT 4 MW													
Secondary		$6	$2	($21)	($12)						$115		$115
Primary		$1,647	$232	($1,996)	($117)						$3,095		$3,095
Subtransmission		$457	$87	($763)	($218)						$979		$979
Class Total	$58,445					$1,723	$273	$1,996	$3,905	$3,359			$7,265
Schedule 90-P	$73,605	$2,151	$231	($2,042)	$340	$2,229	$358	$2,587	$3,800	$2,049	$1,451		$7,300
Schedules 91 & 95	$4,821	$429	$15	($8)	$437	$148	$23	$171	$475	$256	$852	$579	$2,162
Schedules 92	$173	$6	$1	($0)	$6	$5	$1	$6	$7	$4	$13	$5	$30
Totals	$1,035,218	$43,560	$3,499	($11,009)	$36,050	$34,939	$4,898	$39,836	$75,489	$41,968	$126,435	$104,112	$348,005

PORTLAND GENERAL ELECTRIC
Marginal Energy Costs: 2015 Test Period

Schedules	Marginal Energy Cost	Energy Percent		
Schedule 7	$419,840,573	43.03%	$419,840,573	$419,840.57
Schedule 15	$787,636	0.08%	$787,636	$787.64
Schedule 32	$86,120,231	8.83%	$86,120,231	$86,120.23
Schedule 38	$2,486,765	0.25%	$2,486,765	$2,486.76
Schedule 47	$1,042,147	0.11%	$1,042,147	$1,042.15
Schedule 49	$3,897,406	0.40%	$3,897,406	$3,897.41
Schedule 83	$152,587,547	15.64%	$152,587,547	$152,587.55
Schedule 85	$120,889,319	12.39%	$120,889,319	$120,889.32
Schedule 85 1-4 MW	$47,466,348	4.87%	$47,466,348	$47,466.35
Schedule 89 GT 4 MW	$58,482,927	5.99%	$58,482,927	$58,482.93
Schedule 90	$77,032,786	7.90%	$77,032,786	$77,032.79
Schedule 91/95	$4,788,047	0.49%	$4,788,047	$4,788.05
Schedule 92	$176,735	0.02%	$176,735	$176.73
TOTAL	$975,598,466	100.00%	$975,598,466	$975,598.47
combined 85	$168,355,667	17.26%		

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PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2015

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)	Cycle Basis Pct.	Capacity Marginal Costs	Energy Marginal Costs	Capacity Percent	Energy Percent
Schedule 7	7,458,711	$419,841	50.61%	$167,981	$587,822	44.96%	$465,597	$465,849	45.0%	$167,981	$419,841	28.6%	71.4%
Schedule 15	15,972	$788	0.06%	$212	$1,000	0.08%	$792	$792	0.1%	$212	$788	21.2%	78.8%
Schedule 32	1,559,890	$86,120	8.55%	$28,376	$114,496	8.76%	$90,689	$90,492	8.7%	$28,376	$86,120	24.8%	75.2%
Schedule 38	43,566	$2,487	0.21%	$708	$3,195	0.24%	$2,531	$2,533	0.2%	$708	$2,487	22.2%	77.8%
Schedule 47	18,252	$1,042	0.19%	$625	$1,667	0.13%	$1,321	$1,313	0.1%	$625	$1,042	37.5%	62.5%
Schedule 49	69,104	$3,897	0.63%	$2,084	$5,982	0.46%	$4,738	$4,733	0.5%	$2,084	$3,897	34.8%	65.2%
Schedule 83	2,744,338	$152,588	14.57%	$48,350	$200,938	15.37%	$159,157	$158,654	15.3%	$48,350	$152,588	24.1%	75.9%
Schedule 85	2,197,683	$120,889	10.82%	$35,924	$156,814	11.99%	$124,208	$122,357	11.8%	$35,924	$120,889	22.9%	77.1%
Schedule 85 1-4 MW	876,618	$47,466	4.03%	$13,388	$60,854	4.65%	$48,201	$50,157	4.8%	$13,388	$47,466	22.0%	78.0%
Schedule 89 GT 4 MW	1,112,629	$58,483	4.36%	$14,470	$72,953	5.58%	$57,784	$58,361	5.6%	$14,470	$58,483	19.8%	80.2%
Schedule 90	1,466,333	$77,033	5.56%	$18,463	$95,496	7.30%	$75,639	$74,979	7.2%	$18,463	$77,033	19.3%	80.7%
Schedule 91/95	97,094	$4,788	0.39%	$1,290	$6,078	0.46%	$4,814	$4,814	0.5%	$1,290	$4,788	21.2%	78.8%
Schedule 92	3,319	$177	0.01%	$41	$217	0.02%	$172	$173	0.0%	$41	$177	18.7%	81.3%
TOTAL	17,663,507	$975,598	100.0%	$331,913	$1,307,511	100.00%	$1,035,643	$1,035,206		$331,913	$975,598	25.4%	74.6%
Simple Cycle Proxy Plant $/kW				$100.20		**TARGET**	**$1,035,643**						
Projected Peak Load				3,313									
Marginal Capacity Costs ($000)				$331,913									

these numbers are the results of rev. req. allocation, working backward.

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Rate Schedule	2015 SB 838 Amount	2015 SB 1149 Amount	Total EE funding $	Total EE funding %
Schedule 7	$27,612,139	$26,423,221	$54,035,360	53.94%
Schedule 15/515	$95,841	$109,524	$205,365	0.21%
Schedule 32/532	$5,322,807	$5,239,857	$10,562,664	10.54%
Schedule 38/538	$173,156	$180,309	$353,465	0.35%
Schedule 47	$81,577	$98,694	$180,271	0.18%
Schedule 49/549	$219,375	$259,070	$478,445	0.48%
Schedule 83/583	$7,608,994	$7,581,648	$15,190,642	15.16%
Schedule 85/485/585	$7,249,370	$7,523,811	$14,773,181	14.75%
Schedule 89/489/589	$0	$1,584,333	$1,584,333	1.58%
Schedule 90/490/590	$0	$1,724,197	$1,724,197	1.72%
Schedule 91/95/591/595	$527,220	$540,061	$1,067,282	1.07%
Schedule 92/592	$8,517	$8,026	$16,543	0.02%
Schedule 485		$403,213	$403,213	
Schedule 489		$256,089	$256,089	
	$48,898,997	$51,932,052	$100,831,048	
Total net 400 schedules	$48,898,997	$51,272,750	$100,171,747	100%

*assuming 2.7 cents/kWh
*numbers in red are from UE 283 response to CUB DR 37A

Rate Schedule		
Schedule 7		53.94%
Schedule 15/515		0.21%
Schedule 32/532		10.54%
Schedule 38/538		0.35%
Schedule 47		0.18%
Schedule 49/549		0.48%
Schedule 83/583		15.16%
Schedule 85/485/585		14.75%
Schedule 89/489/589		1.58%
Schedule 90/490/590		1.72%
Schedule 91/95/591/595		1.07%
Schedule 92/592		0.02%
Total net 400 schedules		100.00%

source	Resource	mWa	IRP	RPS standards
				min renewable
2013 IRP appendix B page 3	Baseload Gas	653	50.54%	50.00%
2013 IRP appendix B page 3	Wind	280	21.67%	25.00%
2013 IRP appendix B page 3	EE	259	20.05%	20.00%
2013 IRP appendix B page 3	procurement	100	7.74%	5.00%
	total	**1292**	**100.00%**	100.00%
IRP page				
EE funding in mWa				
			1033	
			0.27105518	

	mWh		mWa	percent verify
theoretical traditional resource needs		17663507	2016	50.54%
theoretical renewable needs		7573939	865	21.67%
theoretical total EE needs		7005893	800	20.05%
theoretical total procurement		2704978	309	7.74%
theoretical total resource needs		34948318	3990	100.00%

Rate Schedule	total system share	total system mWa allocated	EE credit allocated	Net EE system mWa allocated	Net EE system % allocated	net EE Wind mWa allocated	net EE procurement mWa allocated	net EE traditional mWa allocated
Schedule 7	43.03%	1716.86	431.41	1285.45	40.30%	348.43	124.44	812.58
Schedule 15/515	0.08%	3.22	1.64	1.58	0.05%	0.43	0.15	1.00
Schedule 32/532	8.83%	352.17	84.33	267.84	8.40%	72.60	25.93	169.31
Schedule 38/538	0.25%	10.17	2.82	7.35	0.23%	1.99	0.71	4.64
Schedule 47	0.11%	4.26	1.44	2.82	0.09%	0.77	0.27	1.78
Schedule 49/549	0.40%	15.94	3.82	12.12	0.38%	3.28	1.17	7.66
Schedule 83/583	15.64%	623.98	121.28	502.70	15.76%	136.26	48.66	317.78
Schedule 85/485/585	17.26%	688.46	117.95	570.51	17.89%	154.64	55.23	360.64
Schedule 89/489/589	5.99%	239.16	12.65	226.51	7.10%	61.40	21.93	143.18
Schedule 90/490/590	7.90%	315.01	13.77	301.25	9.44%	81.65	29.16	190.43
Schedule 91/95/591/595	0.49%	19.58	8.52	11.06	0.35%	3.00	1.07	6.99
Schedule 92/592	0.02%	0.72	0.13	0.59	0.02%	0.16	0.06	0.37
Schedule 485	NA							
Schedule 489	NA							
Total net 400 schedules	100.00%	3990	800	3190	100.00%	864.60	308.79	2016.38

numbers in red from UE 287 Non-Confidential 1400 workpapers file RatespreadGRC15.xlsx tab Mcenergy

Annual Energy Trust Electric savings by sector

from		
	http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf	page 4
	http://energytrust.org/library/reports/2013__Economic_Impacts_Report.pdf	page 2
	http://energytrust.org/library/reports/2013_ETO_Annual_Report.pdf	page 25

ETO System*

aMW	commercial	industrial	residential	total	units	
2008	8.3	6.7	13.7	28.7	mWa	FROM 2013 BRIEF
2009	10.2	7.8	9.3	27.3	mWa	FROM 2013 BRIEF
2010	17.2	15.2	12.5	44.9	mWa	FROM 2013 BRIEF
2011	18.4	14.8	14.1	47.3	mWa	FROM 2013 BRIEF
2012	22.1	14.7	16.1	52.9	mWa	FROM 2013 BRIEF
2013	23.4	16.9	15.4	55.7	mWa	FROM 2013 BRIEF
2014	23.6	18.9	14.8	57.3	mWa	FROM 2013 BRIEF
total	123.2	95	95.9	314.1	mWa	
percent	39.22%	30.25%	30.53%	100.00%		

*all numbers above from http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf

PGE specific

year	amw	units		
			page 10	annual report
2008	18.58	mWa	page 10	http://energytrust.org/library/reports/ETO_RPT_08_annual_report-p.pdf
2009	20.4	mWa	page 12	http://energytrust.org/library/reports/Final_ET_AnnualReport09_singles.pdf
2010	25.6	mWa		http://energytrust.org/library/reports/AnnualReport_2010.pdf
2011	28.18	mWa		
2012	32.23	mWa		
2013	35.62	mWa		
total	160.61	mWa		

year	Commercial mWa savings	Industrial mWa savings	Residential mWa savings	
2008	28.92%	23.34%	47.74%	100.00%
2009	37.36%	28.57%	34.07%	100.00%
2010	38.31%	33.85%	27.84%	100.00%
2011	38.90%	31.29%	29.81%	100.00%
2012	41.78%	27.79%	30.43%	100.00%
2013	42.01%	30.34%	27.65%	100.00%
2014	41.19%	32.98%	25.83%	100.00%

PGE Specific

aMW	commercial	industrial	residential	total	units	
2008	5.26	4.11	9.21	18.58	mWa	ETO 208 annual report to the public utility commission pg12/38
2009	10.2	7.8	9.3	27.3	mWa	ETO 2009 annual report to the public utility commission pg12/39
2010	9.86	8.65	7.09	25.6	mWa	ETO 2011 annual report to the public utility commission pg12/40
2011	18.4	14.8	14.1	47.3	mWa	ETO 2012 annual report to the public utility commission pg12/41
2012	22.1	14.7	16.1	52.9	mWa	ETO 2013 annual report to the public utility commission pg12/42
2013	24.79	17.05	15.96	57.8	mWa	ETO 2014 annual report to the public utility commission pg12/43
total	90.61	67.11	71.76	229.48	mWa	
percent	39.48%	29.24%	31.27%	100.00%		

ETO System

ETO annual report

aMW	commercial	industrial	residential	total	units
2008	7.79	9.4	14.93	32.12	mWa
2009	10.5	9	12.8	32.3	mWa
2010	17.63	15.86	12.16	45.65	mWa
2011	16.2	13.8	16.9	46.9	mWa
2012	22.1	14.7	16.1	52.9	mWa
2013	24.79	17.05	15.96	57.8	mWa
2014	23.6	18.9	14.8	57.3	mWa
total	122.61	98.71	103.65	324.97	mWa
percent	37.73%	30.38%	31.90%	100.00%	

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2015

Schedules	Energy Percent per PGE	System mWa allocation gross ETO	EE mWa	system mWa allocation net ETO	mWa of traditional energy gen	MWa Wind	MC of Wind	Marginal Wind Cost ($000	Mwa of Traditional Generation	NET ETO Energy percent	MC of traditional Energy	Mwa of procurement	COS Calendar Energy
Schedule 7	43.03%	1716.86	431.41	1,285	40.30%	346	0.10	$35	808	40.07%	$390,904,602	124	7,458,711
Schedule 15	0.08%	3.22	1.64	2	0.05%	0	0.10	$0	1	0.03%	$299,984	0	15,972
Schedule 32	8.83%	352.17	84.33	268	8.40%	73	0.10	$7	169	8.40%	$81,956,703	26	1,559,890
Schedule 38	0.25%	10.17	2.82	7	0.23%	2	0.10	$0	5	0.26%	$2,509,019	1	43,566
Schedule 47	0.11%	4.26	1.44	3	0.09%	1	0.10	$0	2	0.09%	$895,532	0	18,252
Schedule 49	0.40%	15.94	3.82	12	0.38%	4	0.10	$0	8	0.41%	$3,981,233	1	69,104
Schedule 83	15.64%	623.98	121.28	503	15.76%	136	0.10	$14	317	15.73%	$153,502,377	49	2,744,338
Schedule 85	17.26%	688.46	117.95	571	17.89%	111	0.10	$11	258	12.80%	$124,888,375	40	2,197,683
Schedule 89 GT 4 MW	5.99%	239.16	12.65	227	7.10%	51	0.10	$5	119	5.90%	$57,594,655	18	1,112,629
Schedule 90	7.90%	315.01	13.77	301	9.44%	83	0.10	$8	193	9.59%	$93,594,630	30	1,466,333
Schedule 91/95	0.49%	19.58	8.52	11	0.35%	5	0.10	$1	12	0.61%	$5,942,875	2	97,094
Schedule 92	0.02%	0.72	0.13	1	0.02%	0	0.10	$0	0	0.02%	$161,085	0	3,319
TOTAL	100%	3,990	800	3,190	100.00%	865			2,016	1	$975,598,466	309	17,663,507

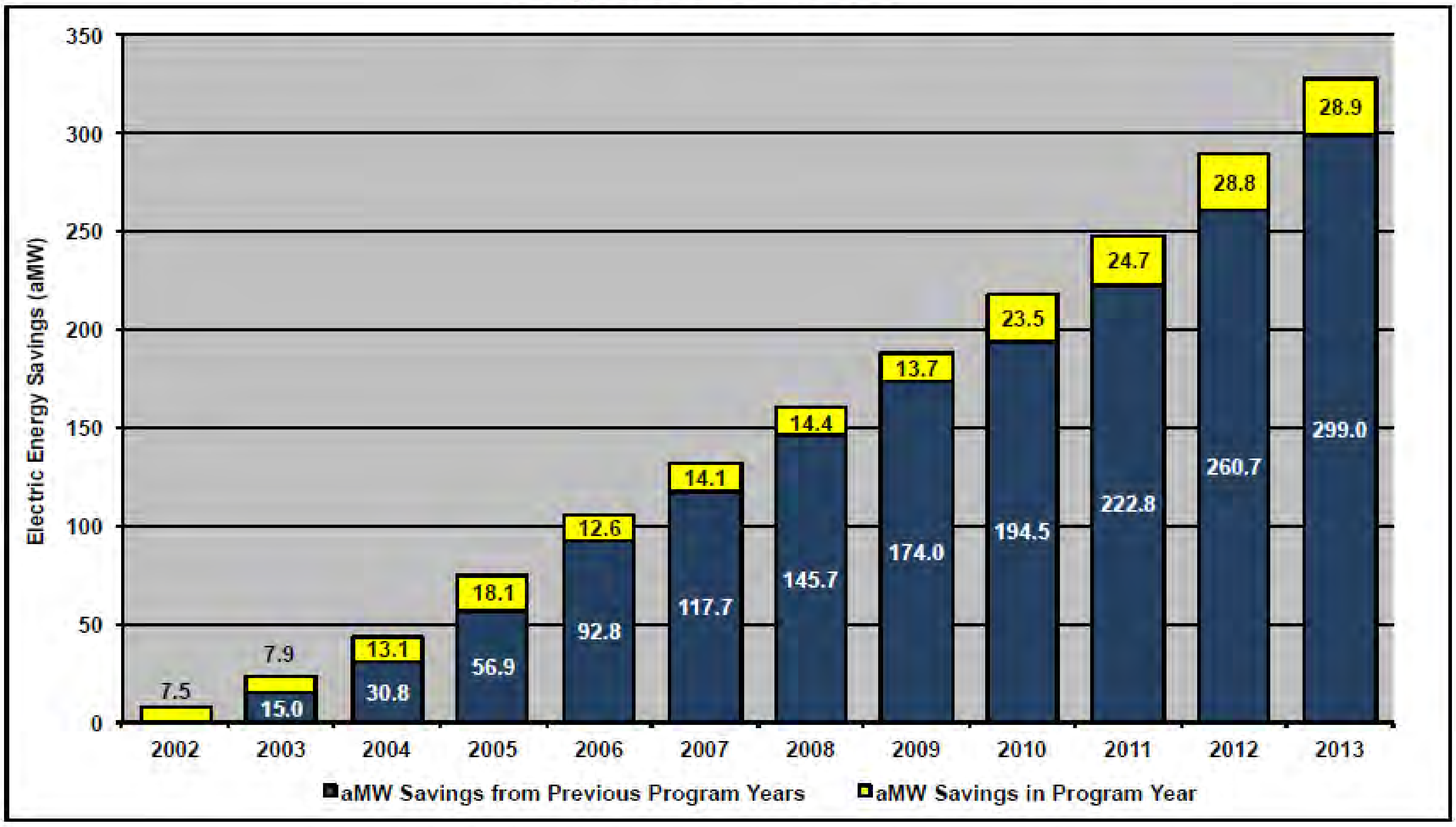
Schedules	CUB Marginal Energy Costs	PGE Marginal Energy Costs		Generation Capacity Allocation	Marginal Capacity Costs ($00	Capacity & Energy Costs ($000)	& Energy Allocation Percent	Capacity & Energy Costs ($000)	Marginal Cycle Basis Costs ($000)	Capacity Capacity & Energy Costs ($000)	CUB proposal Allocated		PGE proposal Allocated
Schedule 7	$393,157.37	$419,840,573	$390,905	50.61%	$167,981	$558,886	42.74%	$442,678	$442,917	$465,597		4.92%	
Schedule 15	$483.64	$787,636	$300	0.06%	$212	$512	0.04%	$406	$406	$792		48.77%	
Schedule 32	$81,920.00	$86,120,231	$81,957	8.55%	$28,376	$110,332	8.44%	$87,391	$87,201	$90,689		3.64%	
Schedule 38	$2,247.14	$2,486,765	$2,509	0.21%	$708	$3,217	0.25%	$2,548	$2,550	$2,531		-0.70%	
Schedule 47	$863.24	$1,042,147	$896	0.19%	$625	$1,521	0.12%	$1,204	$1,198	$1,321		8.79%	
Schedule 49	$3,706.28	$3,897,406	$3,981	0.63%	$2,084	$6,066	0.46%	$4,804	$4,799	$4,738		-1.40%	
Schedule 83	$153,751.41	$152,587,547	$153,502	14.57%	$48,350	$201,853	15.44%	$159,882	$159,376	$159,157		-0.46%	
Schedule 85	$174,492.40	$168,355,667	$124,888	10.82%	$35,924	$160,813	12.30%	$127,375	$125,478	$124,208		-2.55%	
Schedule 89 GT 4 MW	$69,277.36	$58,482,927	$57,595	4.36%	$14,470	$72,064	5.51%	$57,080	$57,650	$57,784		1.22%	
Schedule 90	$92,136.62	$77,032,786	$93,595	5.56%	$18,463	$112,057	8.57%	$88,758	$87,983	$75,639		-17.34%	
Schedule 91/95	$3,382.35	$4,788,047	$5,943	0.39%	$1,290	$7,233	0.55%	$5,729	$5,729	$4,814		-19.00%	
Schedule 92	$180.65	$176,735	$161	0.01%	$41	$202	0.02%	$160	$160	$172		7.20%	
TOTAL	$975,598,466	$975,598,466	$975,598	100.0%	$331,913	$1,307,511	100.00%	$1,035,643	$1,035,412	$1,035,643			
					2016.382								
								$100.20		TARGET	$1,035,643		$1,035,643
								3,313					
								$331,913					

Simple Cycle Proxy Plant $/kW
Projected Peak Load
Marginal Capacity Costs ($000)

	mWa			
n	3990			
theoretical total resource n	865			
theoretical renewable need	800			
total EE needs	309	79.95%	pge energy revenue re	$975,598,466
total procurement	2016			
theoretical traditional resou				
	3190			
Total Resource Needs Net				

math check total gross

Figure 1: Net Electric Energy Savings for Energy Trust Energy Efficiency Programs, 2002—2013



Sources: Calculations by Pinnacle Economics using detailed Energy Trust Program data
Notes: 1) Net electric energy savings have been adjusted for Energy Trust True Up. 2) Net electric energy savings include NEEA electric energy savings.

Report ID: CISB-REV-0012M
Revenue Month: DEC 2013

PORTLAND GENERAL ELECTRIC

Rate Schedule Tracking Elements By Rate

109 Energy Efficiency Funding Adj

Date:1/3/2014 3:57:49AM

		Month To Date		Total To Date	
R/C	Rate	KWH	Amount	KWH	Amount
1	07	878,598,974	3,269,286.67	7,632,209,565	27,986,337.11
	12	0	0.00	5,136,567	18,730.73
	15	1,893,837	11,541.81	22,710,605	137,731.31
	32	150,910,869	517,688.56	1,551,148,311	5,279,885.85
	38	2,796,558	11,206.18	30,668,027	121,310.00
	47	504,182	2,278.93	18,703,669	84,539.62
	485	35,360,766	90,170.18	396,066,246	1,004,193.03
	489	4,000,046	8,680.11	49,333,324	106,718.71
	49	738,580	2,356.16	58,844,968	187,344.97
	515	5	43.86	60	523.43
	532	389,088	1,335.98	4,348,654	14,793.56
	538	0	0.00	0	5.06
	583	5,326,914	15,021.87	62,481,530	174,636.41
	585	5,593,722	14,263.95	72,376,671	180,879.17
	589	424,268	920.66	9,014,512	19,075.72
	83	245,955,175	693,639.08	2,696,670,787	7,547,843.67
	85	177,291,508	452,186.47	2,046,444,755	5,175,478.36
	89	49,063,518	86,005.50	348,299,845	980,518.18
	91	8,055,881	43,218.41	103,150,044	551,911.25
	92	298,808	764.96	3,640,719	9,238.56
	93	32,631	203.95	563,704	3,499.38
	95	311,246	1,689.87	1,409,919	7,642.77
		1,567,546,576	**5,222,503.16**	**15,113,222,482**	**49,592,836.85**
Total		**1,567,546,576**	**5,222,503.16**	**15,113,222,482**	**49,592,836.85**

Report ID: CISB-REV-0012M
Revenue Month: DEC 2013

PORTLAND GENERAL ELECTRIC

Rate Schedule Tracking Elements By Rate

Public Purpose Charge

R/C	Rate	Month To Date KWH	Month To Date Amount	Total To Date KWH	Total To Date Amount
1	07	878,599,119	2,765,308.06	7,632,211,904	23,933,242.57
	12	0	0.00	5,136,567	15,829.42
	15	1,899,667	10,429.58	22,780,154	125,103.94
	201	0	0.00	0	5.49
	215	0	302.49	0	3,085.61
	216	0	12.05	0	131.06
	217	0	0.90	0	10.80
	300	0	16.02	0	124.81
	32	151,019,083	444,493.50	1,552,169,628	4,645,087.63
	38	2,811,932	10,017.77	30,758,532	109,534.57
	47	504,132	1,649.79	18,703,467	73,044.31
	485	38,142,687	34,292.76	428,859,330	396,677.01
	489	60,340,997	38,989.18	782,432,205	493,417.64
	49	746,198	2,046.52	59,038,519	158,727.65
	515	5	19.92	60	239.30
	532	411,894	643.76	4,481,956	7,350.05
	538	0	0.00	0	5.28
	583	5,567,200	6,923.91	64,184,455	82,413.33
	585	5,714,117	6,327.92	73,045,045	82,608.89
	589	2,180,217	2,115.84	29,293,516	28,582.97
	75	52,277,520	19,423.51	647,145,120	215,052.08
	83	248,640,087	612,382.74	2,732,308,326	6,795,563.34
	85	187,608,464	423,306.00	2,145,691,007	4,868,868.98
	89	240,173,195	375,356.96	2,614,611,331	4,056,320.62
	91	8,059,822	38,810.10	103,198,744	503,341.62
	92	298,808	681.10	3,640,719	8,303.62
	93	32,631	190.46	563,704	3,188.06
	95	311,246	3,242.06	1,409,919	13,450.14
		1,885,339,021	**4,796,982.90**	**18,951,664,208**	**46,619,310.79**
Total		**1,885,339,021**	**4,796,982.90**	**18,951,664,208**	**46,619,310.79**

year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
SB 838 savings (aMW)	2.1	4.8	7.21	13.24	17.36	17.43	16.88	17.56	17.36	$\boxed{\textbf{20.6}}$	134.5367
total savings from measures in MWh	18396	42048	63159.6	115982.4	152073.6	152686.8	147868.8	153825.6	152073.6	180427.5	
annualized savings (10 year life) in MWH	1839.6	4204.8	6315.96	11598.24	15207.36	15268.68	14786.88	15382.56	15207.36	18042.75	
levelized cost (cents/kwh)	2.1	2.8	2.5	2.9	2.7	2.4	2.6	2.6	2.6	2.6	2.58
annualized cost of power cents per kWh	3863160	11773440	15789900	33634896	41059872	36644832	38445888	39994656	39539136	46911151	
levelized cost (cents/kwh) for 2008-2017	2.610487841										
total SB 838 embedded in test year (10-year life)	134.5367472										
total MWh	1178541.905										
total amount of SB 838 EE embedded in 2018 rates	117854.1905										

notes:
The source for the 2008 -- 2015 is ETO Annual Reports to OPUC
The source for the 2017 is CUB DR 03-A
There was not source for 2016, but because the SB 838 dollars were nearly identical to 2012, CUB assumed similar performance.
The soruce for levelized cost was ETO Annual Reporst to OPUC. Did not break out 838 versus 1149.

assumed 10 year measure life
10 year measure life is most common measure life: https://energytrust.org/wp-content/uploads/2016/12/021611_ResourceAssessment.pdf

PGE 2018 Marginal Energy and Capacity Cost	
(UE 319/PGE/1301)	32.33
value per MWh of EE in 2018 ($/MWh	6.225121591
credit of SB 838 paying customers	7,336,566.66

Rate Schedule	2015 SB 838 Amount		Credit	
Schedule 7	$27,612,139	56.47%	$	4,142,790
Schedule 15/515	$95,841	0.20%	$	14,379
Schedule 32/532	$5,322,807	10.89%	$	798,608
Schedule 38/538	$173,156	0.35%	$	25,979
Schedule 47	$81,577	0.17%	$	12,239
Schedule 49/549	$219,375	0.45%	$	32,914
Schedule 83/583	$7,608,994	15.56%	$	1,141,616
Schedule 85/485/585	$7,249,370	14.83%	$	1,087,660
Schedule 89/489/589	$0	0.00%	$	-
Schedule 90/490/590	$0	0.00%	$	-
Schedule 91/95/591/595	$527,220	1.08%	$	79,102
Schedule 92/592	$8,517	0.02%	$	1,278
Schedule 485				
Schedule 489				
	$48,898,997		$	7,336,567

April 4, 2017

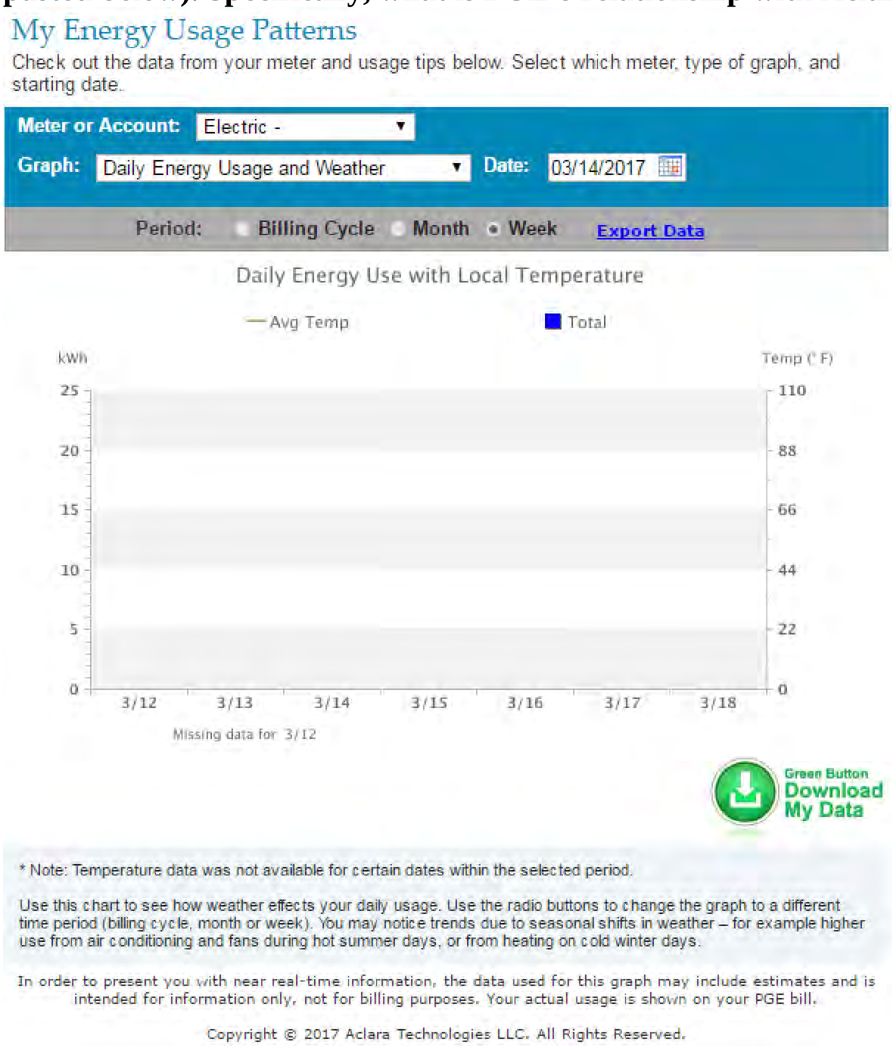
TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 268
Dated March 21, 2017

Request:

Please describe who manages the Daily/Hourly Usage feature of the Energy Tracker (as pasted below). Specifically, what is PGE's relationship with Aclara Technologies LLC?



Response:

Aclara Technologies is PGE's vendor that operates the Daily/Hourly usage feature of Energy Tracker. Aclara hosts and formats the customers' electric usage into easy to understand graphs, displays temperature overlays, compares different date ranges, and allows downloading of the data for the Daily/Hourly usage feature of Energy Tracker.

Aclara processes the customer's billing and meter data to create useful graphs about their energy usage, comparison of their bills, and offers suggestions on how to save money on their electric bills. When a customer selects an Energy Tracker link on the website (i.e. Daily/Hourly Usage, Compare Bills, or Ways to Save), then up to 13 months of billing data and meter data is sent to Aclara to provide the customer with personalized energy usage and savings insights.

RAP Celebrating 20 Years

Recovering Smart Grid Costs In Electricity Rates

Jim Lazar
Senior Advisor

May, 2013

The Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602
Phone: 802-223-8199
web: www.raponline.org

About Jim Lazar

- Consulting Economist specializing in utility rates and resource planning.
- Expert witness in more than 100 regulatory proceedings before federal, state, local regulators.
- Author of several books and guides on issues relating to regulation.
- Senior Advisor with Regulatory Assistance Project, providing training and technical assistance to utility regulators worldwide.
- Rate consultant to BWP since 2000.

What Are The Costs of Smart Grid?

- **Capital Costs:**
  - Smart meters
  - Data collection network (wifi grid in Burbank)
  - Distribution system controls
  - Meter data management system (hardware and software)
- **Operating Costs:**
  - Software development, implementation and training
  - Hardware maintenance (meters, wifi)
  - Customer service (education)

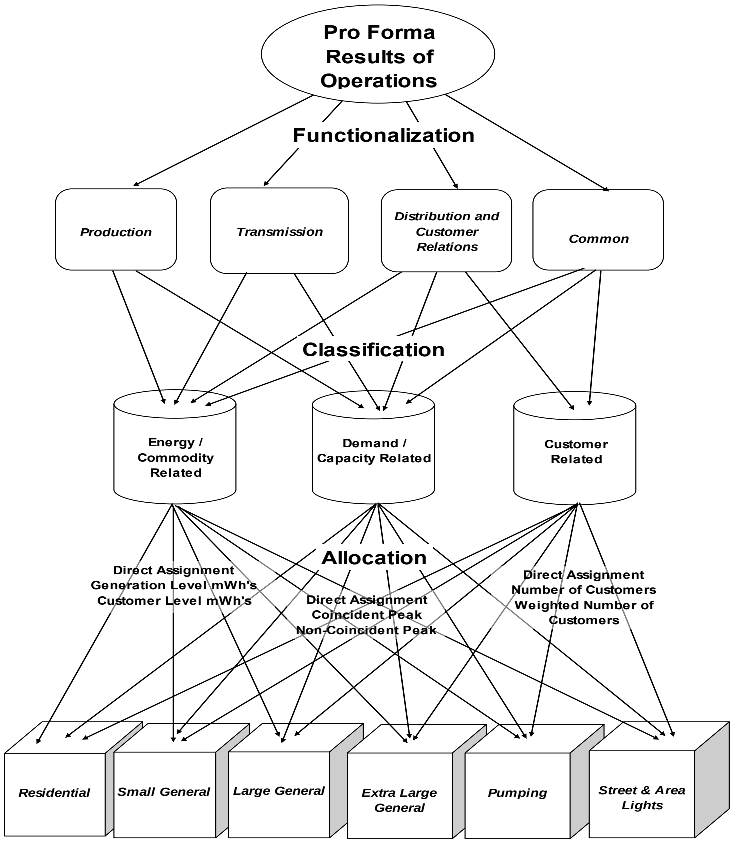
What Are The Benefits of Smart Grid?

- Reduced O&M Expense for meter reading
- Remote shut-off and turn-on
- Reliability Improvement:
- Distribution Automation
- Peak load reduction through Time of Use and Critical Peak Pricing
- Loss reduction: Voltage Control and Power Factor Correction
- Loss Reduction:Phase balancing on the fly

How Would Costs of This Type Be Recovered "Normally?"

- In a traditional cost of service study, costs are:
- Functionalized
  - Prod, Trans, Dist, Common
- Classified
  - Demand, Energy, Customer
- Allocated
  - Residential, Commercial, Industrial

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Functionalization and Classification Should Track Benefits

- Smart Meters do more than conventional meters.
- The system works together to provide system benefits.
- Capital (smart meters) is substituting for operating (meter readers, station meters, load research meters, and more)
- Investment in computers and software are up sharply.
- Distribution system controls reduce peak capacity requirements and reduce energy losses.

Treating Smart Grid Grants

Smart grid grants have been used for both capital investment in hardware, investment in software, and staffing costs during the transition.

- Net the grants out of the amount of plant booked to plant in service.
- Net the amount spent from grants on training and startup from O&M expense

Benefits: O&M Expense

- Cost savings in meter operations and transportation expense are significant.
- These are offset by higher capital costs and data management costs

Meter Operations Impact Metrics	% Change in Improvement
Change in meter operations cost	-13% to -77%
Change in vehicle miles driven, vehicle fuel consumption, and CO_2 emissions	-12% to -59%

Source: USDOE, 2012

Benefits: Peak Demand

Project Elements	OG&E	MMLD	SVE
Number of customers	6,000 residential customers	500 residential customers	600 mostly residential customers
Time-based rate(s)	Time-of-use and variable peak pricing with critical peak pricing components	Critical peak pricing	Critical peak pricing
Customer systems	In-home displays, programmable communicating thermostats, web portals	Web portals	Web portals
Peak demand reduction during critical peak events	Up to 30%	37%	Up to 25%
Customer acceptance	Positive experience, many reduced electricity bills	Positive experience, but did not use the web portals often	Interested in continued participation, many reduced electricity bills

Table ES-1. Summary of the Initial Results (Summer 2011)

Energy solutions
for a changing world

Source: USDOE, 2012

Benefits: Reliability

Reliability Indices	Description	Range of Percent Changes
SAIFI	System Average Interruption Frequency Index (outages)	-11% to -49%
MAIFI	Momentary Average Interruption Frequency Index (interruptions)	-13% to -35%
SAIDI	System Average Interruption Duration Index (minutes)	+4% to -56%
CAIDI	Customer Average Interruption Duration Index (minutes)	+29% to -15%

Table ES-1. Changes in Reliability Indices from Automated Feeder Switching

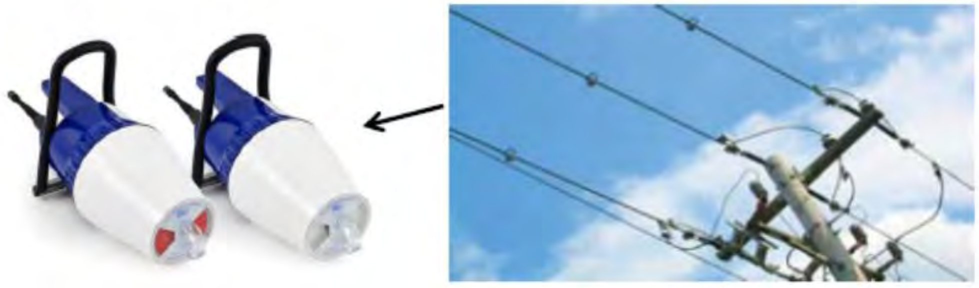


Figure 3. Example Remote Fault Indicator

Source: USDOE, 2012

Benefits: Voltage Control

Multiple Elements

- Lower peak demand
- Lower losses
- Lower O&M costs
- Less Expensive Distribution Upgrades

Improvement Area	Impacts	Primary Benefits
Better voltage control	Lower real power (MW) peak demand from CVR	Reduce capacity payments and/or defer capacity additions/upgrades
	Lower real power (MWh) consumption from CVR	Reduce fuel consumption with lower greenhouse gas and polluting emissions
Better VAR control	Lower reactive power (MVAR) peak demand	Reduce capacity payments and/or defer capacity additions/upgrades
	Lower line losses (MW)	Reduce fuel consumption and environmental emissions
Better operations and maintenance	Fewer service trips	Reduce O&M cost and vehicle emissions
Better integration of distributed energy resources	Acceptable voltage profiles over a wider range of generation and load conditions	Less expensive distribution system upgrades

Energy solutions
for a changing world

So, What's The Problem?

- Traditional metering, meter reading, and billing costs are treated as 100% customer-related in cost of service studies.
- Traditional distribution system components are often treated as 100% demand-related in cost of service studies.
- Now we have new categories of equipment performing multiple functions to manage peak demand, reduce line losses, improve reliability, and provide metering functions.
- Cost allocation and rate design must adapt.

The Methods For Classification and Allocation Must Change

Smart Grid Element	Pre-Smart Grid Element	"Traditional" FERC Account	Traditional Classification		Smart Grid Classification
Smart Meters	Meters	370	Customer		Demand / Energy / Customer
Distribution Control Devices	Station Equipment	362	Demand		Demand / Energy
Data Collection System	Meter Readers	902	Customer		Demand / Energy / Customer
Meter Data Management Syste	General Plant	391 - 397	Subtotal PTDC		Demand / Energy / Customer
Smart Grid Managers	Customer Accounts Supervision	901	Customer		Demand / Energy
Energy Storage Devices (Batteries; Ice Bear)	Installations on Customer Premises	371	Customer		Demand / Energy

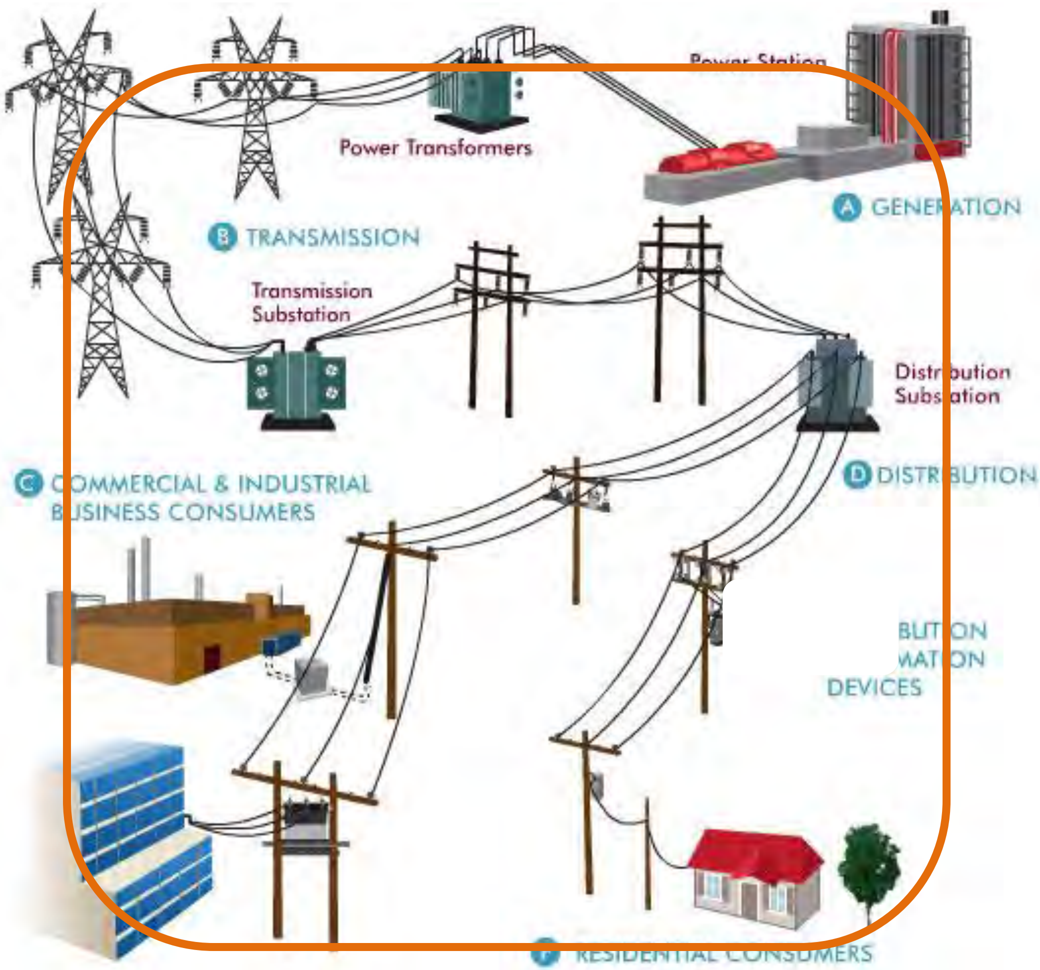
Including Costs In Rate Design

- If benefits are > costs, then all rate elements should be moderated by smart grid investments.
- This means that the savings should be apportioned between customer charges, demand charges, and energy charges.
- If the end-result is an increase in customer charges, and decreases in other rate elements, then not all customers will benefit from smart grid investments.
- There are probably some customers (very small users) for whom smart meter investments are uneconomic, but there is a benefit to system uniformity.

Example of a Service That Smart Grid Makes Possible

- Rooftop PV is a rapidly expanding resource for utilities.
- It creates challenges for operations, and challenges for revenues.
- Smart grid lets us know where the loads are, where the resources are, and adapt the distribution system in real-time to optimize for losses and reliability.
- Net metering is perceived by utilities to be a subsidy.
- A new rate design may be appropriate for PV customers.

Net-Metering Is An Infant-Industry Subsidy



Traditional bundled utility rates pay for all costs of the system.

Power supply
Transmission
Distribution
Customer Service
Billing and Collection

Typically (and ideally) only billing and collection are recovered $/customer.

Which means all other costs are $/kW or $/kWh

Current Net-Metering Rate Design (BWP)

			Rate	1,000 kWh Customer	
				Usage	Bill
Customer Service Charge			$ 4.87	1	$ 4.87
First 250 kwh			$ 0.11	250	$ 28.60
Next 500 kwh			$ 0.15	500	$ 76.40
Over 750 kWh			$ 0.17	250	$ 43.58
		Total:		1000	$ 153.45

Without PV System

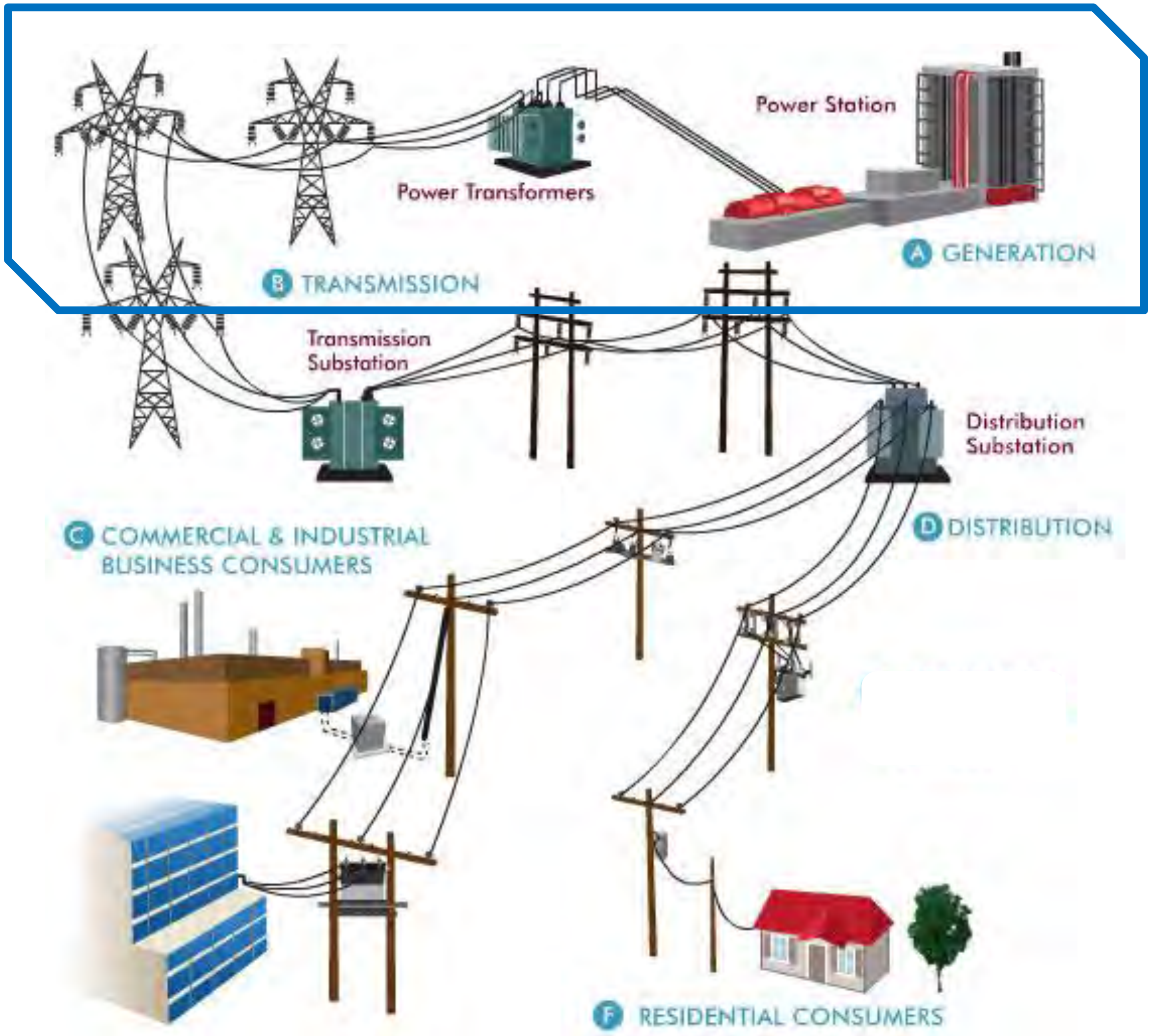
			Rate	1,000 kWh Customer	
				Usage	Bill
Customer Service Charge			$ 4.87	1	$ 4.87
First 250 kwh			$ 0.11	0	$ -
Next 500 kwh			$ 0.15	0	$ -
Over 750 kWh			$ 0.17	0	$ -
		Total:		0	$ 4.87

With PV System producing 1,000 kWh

Bi-Directional Pricing Charges All Customers For What They Use

- Customers using exclusively grid power pay for production, transmission, network distribution, local distribution, and customer service.
- Self-generation customers pay for the full grid for their consumption <u>from</u> the grid, and <u>also</u> pay for local distribution when they are surplus, to help pay for finding customers for their excess power.

Bulk Power Supply Costs



Production and High-Voltage Transmission

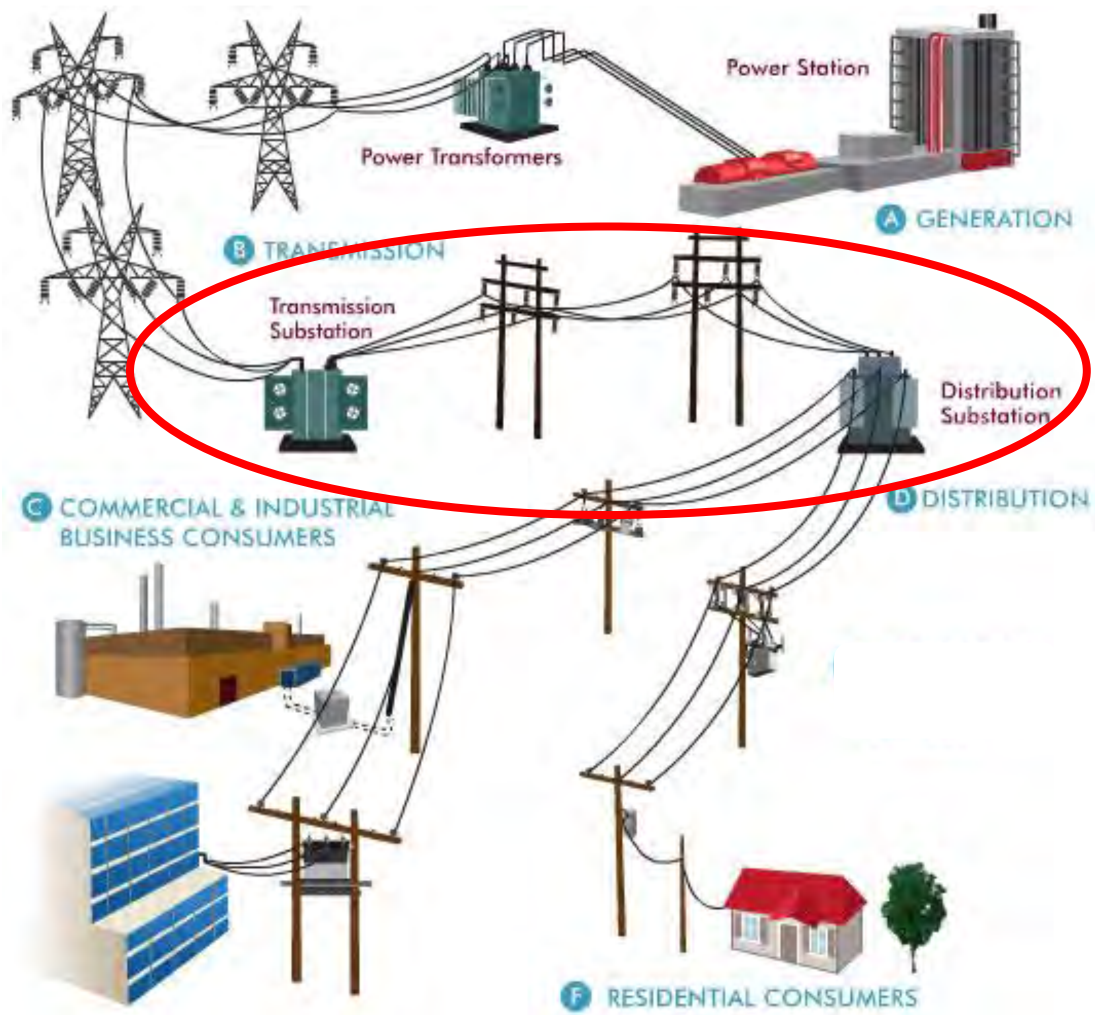
Common to all customers using grid power.

Recover on a Demand/Energy / TOU / Seasonal / Real-Time basis (different discussion)

On-Peak: $ .12/kWh
Mid-Peak: $ .08/kWh
Off-Peak: $ .05/kWh

Critical Peak: $.50/kWh

Network Sub-transmission and Distribution Costs



Common to all customers taking grid power.

34kV, 69kV, 115 kV

Ends at distribution substation

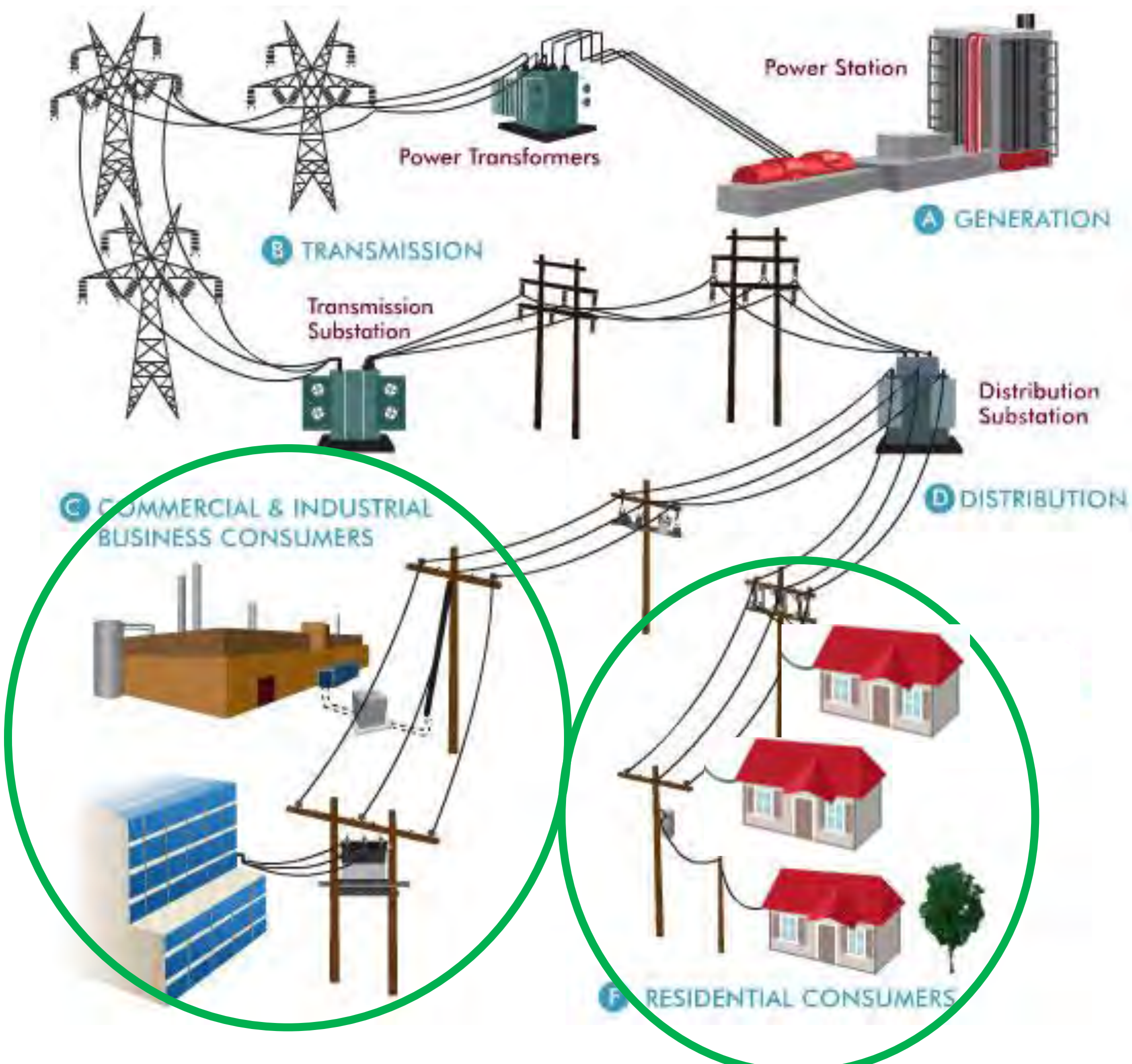
Incurred to meet energy requirements

Sized to meet peak demand

Recover on a demand and energy basis from all customers

Demand-Metered: $4/kW/mo
Energy-Metered: $.01/kWh

Local Distribution Costs



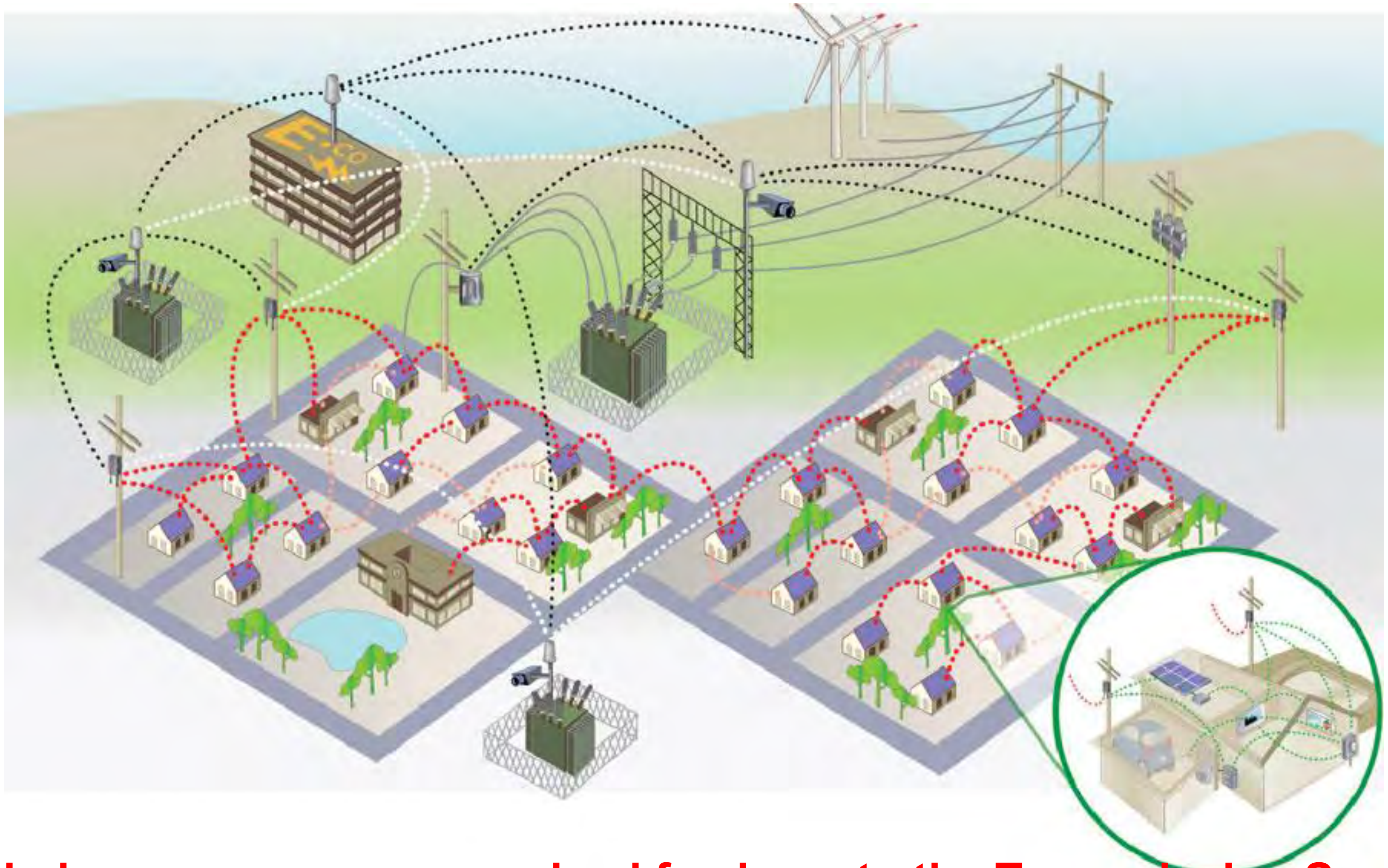
Localized networks that serve only customers in the immediate area.

Some higher-voltage C&I customers take directly from distribution substation, and do not use these costs (and should not pay for these costs)

Local distribution costs recovered bi-directionally from all users.

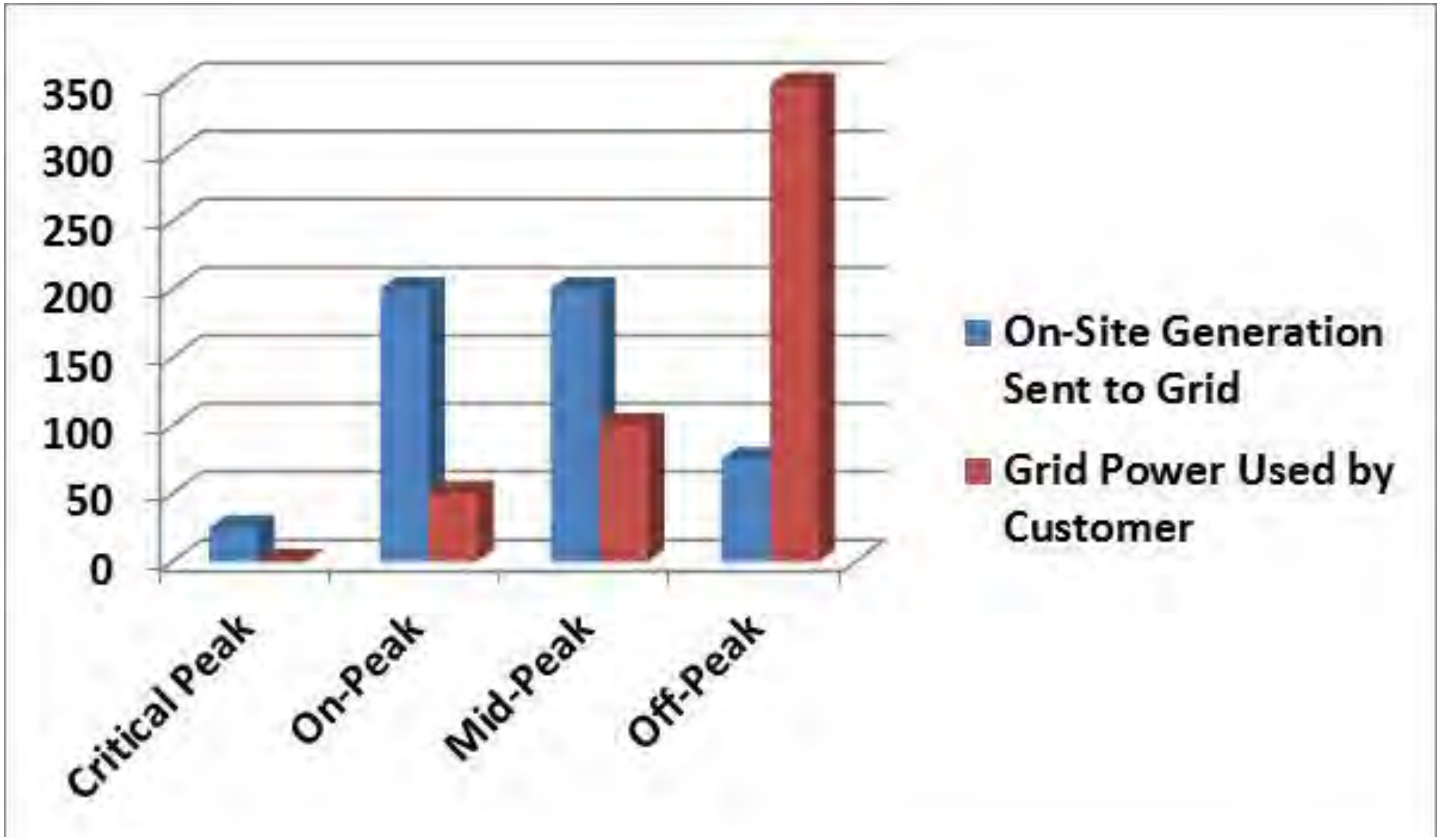
$.02/kWh either direction

Argument: PV customers need a grid and should help pay for it.



But their excess power <u>never</u> backfeeds up to the Transmission System. It stays within the local distribution system. So, only charge them for LOCAL DISTRIBUTION for power they upload to the grid.

Argument: PV customers provide valuable on-peak power to the grid.



So, pay them a TOU price for the power they provide, and charge them a TOU price for the power they use.

Effect of Bi-Directional Pricing

- Step 1: Break down the usage between that produced on-site, and that taken from or sent to the grid.

		Total Usage	Total On-Site Generation	On-Site Generation Used On-Site	On-Site Generation Sent to Grid	Grid Power Used by Customer
Critical Peak		50	75	50	25	0
On-Peak		150	300	100	200	50
Mid-Peak		300	400	200	200	100
Off-Peak		500	225	150	75	350
Total		1,000	1,000	500	500	500

Effect of Bi-Directional Pricing

- Step 2: Apply a Time of Use Rate, with unbundling of Network Distribution from Local Distribution

Customer Service Charge	$	4.87
Power Supply Charge		
Critical Peak	$	0.50
On-Peak	$	0.12
Mid-Peak	$	0.08
Off-Peak	$	0.05
Network Distribution	$	0.01
Local Distribution	$	0.02

Effect of Bi-Directional Pricing

- Step 3: Compute Customer Bill

		Credit for PV	Charge for Grid Power
Customer Service Charge	$ 4.87		$ 4.87
Power Supply Charge			
Critical Peak	$ 0.50	$ (12.50)	$ -
On-Peak	$ 0.12	$ (24.00)	$ 6.00
Mid-Peak	$ 0.08	$ (16.00)	$ 8.00
Off-Peak	$ 0.05	$ (3.75)	$ 17.50
Network Distribution	$ 0.01		$ 5.00
Local Distribution	$ 0.02	$ 10.00	$ 10.00
Subtotal:		$ (46.25)	$ 51.37
Total:			**$ 5.12**
Total Payment for Distribution:			$ 29.87
Net Cost for Power:			$ (24.75)

The bi-directional rate enabled by smart grid investment allows a cost-based rate for energy and delivery.

Customer bill about the same.

But paying $30/month for distribution service.

Cost Recovery For Smart Grid Bottom Line

- Smart grid investments are made primarily to provide demand and energy savings.
- Smart grid cost recovery should follow the benefits – meaning classification and allocation on an energy and demand basis.
- Smart grid investment enables an alternative to traditional pricing that can be devised to be compensatory to both PV customers for the value of power they deliver to the system, **and** recover distribution system costs from PV customers.

Suggested Publications

- **Effect of Smart Metering on Electricity Prices**, European Parliament, 2012
  http://www.lbst.de/ressources/docs2012/EP-11_EFFECT-OF-SMART-METERING-ON-ELECTRITY-PRICES_PE-475-093_LQ.pdf
- **Operations and Maintenance Savings from Advanced Metering Infrastructure - Initial Results**
- **Reliability Improvements from the Application of Distribution Automation Technologies - Initial Results**
- **Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems - Initial Results**
- **Application of Automated Controls for Voltage and Reactive Power Management - Initial Results**

  http://www.smartgrid.gov/library

About RAP

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts that focuses on the long-term economic and environmental sustainability of the power and natural gas sectors. RAP has deep expertise in regulatory and market policies that:

- Promote economic efficiency
- Protect the environment
- Ensure system reliability
- Allocate system benefits fairly among all consumers

Learn more about RAP at www.raponline.org

Jim Lazar, RAP Senior Advisor
jlazar@raponline.org

April 11, 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. 392
Dated March 28, 2017

Request:

Please explain how the CET project improves PGE's ability for customer-designated third parties to more easily access customer interval meter data than the current system?

Response:

For security purposes, PGE does not allow third parties access to data from the current system or future systems. For a third party to obtain the information, the customer must download the information from the website or contact PGE through the contact center to download and send the information. A third party could use the customer's login information, but the customer would have to provide their username and password to obtain the information.

The new system will house all interval data for customers and have a more robust and automated validation processes. Both PGE customers and Customer Service Representatives will be able to download their data, however, the request must be initiated by the customer.

April 11, 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. 393
Dated March 28, 2017

Request:

Please explain how the CET project improves PGE's ability to leverage the company's Advanced Metering Infrastructure (AMI) for the scaling of demand response programs and tariffs like Critical Peak Pricing and Peak Time Rebates across a much wider swath of residential and small-commercial customers.

Response:

PGE's current Meter Data Management (MDM) system is ill-equipped to handle the validation and transfer of data necessary to operate pilot programs at scale, particularly in the case of residential pricing. The current system requires onerous manual validation of data used in billing, which cannot expand to the potentially tens of thousands of customers that would enroll in full-scale programs.

Additionally, data transfer between the current systems and third parties is currently a highly manual process. The new systems will provide a platform for standardized and streamlined transfer of data, such as enrollments and eligibility, reducing the cost and effort required to scale these programs.

Please see PGE's response to OPUC Data Request No. 265 for a description of PGE's MDM system. The MDM system is a component of PGE's AMI. The Customer Care & Billing Customer Information System (CIS) and the MDM system will provide a more systematic approach to program management for PGE's demand response (DR) programs, including:

- Improving insight into customer enrollment and un-enrollment in DR programs and the timing associated with the enrollment process;
- Improving clarity of the configuration of DR programs, such as account, premise and meter set-up;
- Allowing for a more streamlined and timely process for developing and setting-up new rate schedules;

- Allowing for transparency of data tracking between the CIS and MDM systems for PGE employees;
- Capturing interval data for all customers in a single application with more robust and automated validation processes; and
- Improving timing coordination with PGE's third-party vendors who assist PGE with the execution of DR programs to determine the best load shifting and load reduction strategies as well as everyday energy saving opportunities for our customers.

April 11, 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. 395
Dated March 28, 2017

Request:

Please explain how the CET project will improve PGE's ability to target and promote energy efficiency and optional customer services like Clean Wind, demand response programs, CPP and/or PTR.

Response:

The new Customer Information System (CIS) will improve the targeting of programs through better tracking of end user data and more seamless integration our new Meter Data Management (MDM) system. Users of both systems will have access to historical program participation, usage profiles, and payment behavior. Previously these data were stored in disparate systems and were only accessible by advanced users with higher skills and access to the system.

The new system builds the foundation upon which PGE can develop future pricing programs. The system is more widely used across utilities, so the changing needs of the industry are more easily updated in the system through upgrades.

There will also be new fields tracked in the system to better understand customer preferences and eligibility for programs. For example, when customers call PGE, the system will identify for which programs customers are eligible based on their information so we can offer the programs that best suit them. In addition, if a customer declines to participate in a program, there will be visibility in the system so that PGE will not offer the same program again the next time the customer calls.

April 11, 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. 394
Dated March 28, 2017

<u>Request:</u>

At PGE/900/4 PGE states that the 13% increase in costs for customer service O&M in 2018 is related to cost escalations, new programs (e.g., energy storage), and IT charges/allocations. Please provide an estimated dollar amount associated with these three categories of increases. Please list the new programs driving cost increases and describe their cost impacts on customer service O&M. For example, what are the cost impacts of PGE's energy storage program and how is this not covered by the $210,000 for energy storage in the R&D budget? [1]

<u>Response:</u>

PGE estimates that cost escalation accounts for $2.2 million of the overall increase in costs for customer service O&M in 2018. Escalation was calculated by escalating PGE's 2016 budget by the 2018 escalation rates.

See PGE's Exhibit 900 work papers for increases in IT costs. This increase includes major cost drivers that are first charged to a balance sheet account and then allocated to the expense accounts for various operating areas, such as Customer Service. These costs include IT work in the areas of voice, data, network, communication, business recovery, the data center, and office systems.

See PGE's response to OPUC Data Request No. 251 for costs associated with new programs such as energy storage, electric vehicles, emerging technology, distributed generation and demand response.

Energy Storage has $300,000 budgeted in Customer Service O&M specifically dedicated toward ongoing operational support of the storage deployment(s) we anticipate will be underway in response to HB 2193. The R&D budget for energy storage includes projects that advance PGE's

[1] *See* PGE/600/15 for a cost summary of PGE's R&D budget

ongoing knowledge and skills acquisition related to emerging storage technologies. See PGE Exhibit 604 for a list of R&D projects related to energy storage.

April 6, 2017

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to CUB Data Request No. 005
Dated March 27, 2017

Request:

PGE states that the Company has a strong desire to maintain a capital structure consisting of 50% long-term debt and 50% equity. (Ex. 1000, pages 6 & 21). In addition to PGE's explanation in the testimony presented in Exhibit 1000, please provide any additional analysis PGE has conducted to determine that a 50-50 debt-to-equity ratio is optimal.

Response:

As discussed in its testimony, PGE intends to maintain a 50% equity capital structure for several reasons (see PGE Exhibit 1000, pages 21 through 24 for additional details):

- To support PGE's capital needs and offset the leverage and risk to finance its capital expenditure program
- Offset the leverage imputed by the rating agencies due to purchased power
- Maintain solid financials in the face of a variety of business risks

Additionally, PGE has examined data from across the industry. Attachment 005-A provides results across all utilities for both recent rate case results looking back as far as 2015, and currently pending rate cases. For the former, the average equity component was 50.1% and for pending cases its 50.8%. PGE also looked specifically at its current peer group and the average for past rate cases is 51.0% (see Attachment 005-B). Thus, PGE's request for a 50/50 capital structure is in line with utilities broadly and compared to its peer group.

UE 319

Attachment 005-A

Provided in Electronic Format only

Average Equity Component
US Electric Utilities Recent and Pending Rate Cases

UE 319

Attachment 005-B

Provided in Electronic Format only

Average Equity Component
PGE Peer Group Rate Cases

CUB Confidential Exhibit 113 is confidential and will be provided to parties who have signed Protective Order 17-057.

State	Company	Parent Company Ticker	Document Filing Date	Common Equity to Total Capital (%)
Kansas	Kansas City Power & Light	GXP	11/9/2016	NA
Alaska	Alaska Electric Light Power	AVA	9/16/2016	58.18
Hawaii	Maui Electric Company Ltd	HE	12/30/2014	57.43
Hawaii	Hawaiian Electric Co.	HE	12/16/2016	57.36
Hawaii	Hawaii Electric Light Co	HE	9/19/2016	57.12
Arizona	Arizona Public Service Co.	PNW	6/1/2016	55.80
New Hampshire	Liberty Utilities Granite St	AQN	4/29/2016	55.00
New Mexico	Southwestern Public Service Co	XEL	11/1/2016	53.97
Minnesota	ALLETE (Minnesota Power)	ALE	11/2/2016	53.81
Massachusetts	NSTAR Electric Co.	ES	1/17/2017	53.37
Massachusetts	Western Massachusetts	ES	1/17/2017	53.34
Kentucky	Kentucky Utilities Co.	PPL	11/23/2016	53.28
Kentucky	Louisville Gas & Electric Co.	PPL	11/23/2016	53.27
Minnesota	Northern States Power Co. - MN	XEL	11/2/2015	52.50
New Hampshire	Unitil Energy Systems Inc.	UTL	4/29/2016	50.97
Ohio	Duke Energy Ohio Inc.	DUK	3/2/2017	50.75
North Dakota	MDU Resources Group Inc.	MDU	10/14/2016	50.23
Maryland	Potomac Electric Power Co.	EXC	3/24/2017	50.15

State	Company	Parent Company Ticker	Document Filing Date	Common Equity to Total Capital (%)
Oregon	Portland General Electric Co.	POR	2/28/2017	50.00
Ohio	Dayton Power and Light Co.	AES	11/30/2015	50.00
Missouri	Kansas City Power & Light	GXP	7/1/2016	49.88
New Mexico	Public Service Co. of NM	PNM	12/7/2016	49.61
Virginia	Virginia Electric & Power Co.	D	12/1/2016	49.49
Virginia	Virginia Electric & Power Co.	D	10/3/2016	49.49
Virginia	Virginia Electric & Power Co.	D	10/3/2016	49.49
Virginia	Virginia Electric & Power Co.	D	10/3/2016	49.49
Delaware	Delmarva Power & Light Co.	EXC	5/17/2016	49.44
District of Columbia	Potomac Electric Power Co.	EXC	6/30/2016	49.14
Washington	Puget Sound Energy Inc.		1/13/2017	48.50
Texas	Southwestern Electric Power Co	AEP	12/16/2016	48.46
Texas	El Paso Electric Co.	EE	2/13/2017	48.35
Virginia	Appalachian Power Co.	AEP	11/17/2016	46.27
Texas	Oncor Electric Delivery Co.		3/17/2017	45.00
Texas	Sharyland Utilities		4/29/2016	45.00
Florida	Gulf Power Co.	SO	10/12/2016	40.07

State	Company	Parent Company Ticker	Document Filing Date	Common Equity to Total Capital (%)
Arkansas	Oklahoma Gas and Electric Co.	OGE	8/25/2016	39.71
			Average	50.68

State	Company	Parent Company Ticker	Date	Common Equity to Total Capital (%)
Indiana	Indianapolis Power & Light Co.	AES	12/22/2016	39.55
Kansas	Empire District Electric Co.	AQN	9/16/2016	49.69
Arkansas	Entergy Arkansas Inc.	ETR	7/22/2016	30.79
Maryland	Delmarva Power & Light Co.	EXC	7/20/2016	49.10
Missouri	Union Electric Co.	AEE	7/1/2016	51.80
Connecticut	United Illuminating Co.		7/1/2016	52.00
South Carolina	Duke Energy Progress LLC	DUK	7/1/2016	53.00
South Carolina	South Carolina Electric & Gas	SCG	6/27/2016	51.18
Wyoming	MDU Resources Group Inc.	MDU	6/10/2016	50.99
Nevada	Sierra Pacific Power Co.	BRK.A	6/6/2016	48.03
Virginia	Virginia Electric & Power Co.	D	6/1/2016	49.49
Virginia	Virginia Electric & Power Co.	D	6/1/2016	45.49
Virginia	Virginia Electric & Power Co.	D	6/1/2016	49.49
Virginia	Virginia Electric & Power Co.	D	6/1/2016	49.49
Virginia	Virginia Electric & Power Co.	D	6/1/2016	49.49
Idaho	Avista Corp.	AVA	5/26/2016	50.00
Wisconsin	Wisconsin Power and Light Co	LNT	5/20/2016	52.20

New Jersey	Rockland Electric Company	ED	5/13/2016	49.81
Colorado	Black Hills Colorado Electric	BKH	5/3/2016	50.92
Pennsylvania	Metropolitan Edison Co.	FE	4/28/2016	51.20
Pennsylvania	Pennsylvania Electric Co.	FE	4/28/2016	52.60
Pennsylvania	Pennsylvania Power Co.	FE	4/28/2016	50.10
Pennsylvania	West Penn Power Co.	FE	4/28/2016	50.30
New Jersey	Jersey Cntrl Power & Light Co.	FE	4/28/2016	54.00
Maryland	Potomac Electric Power Co.	EXC	4/19/2016	49.55
Illinois	Ameren Illinois	AEE	4/15/2016	50.00
Illinois	Commonwealth Edison Co.	EXC	4/13/2016	45.62
Wisconsin	Madison Gas and Electric Co.	MGEE	4/8/2016	58.06
Virginia	Appalachian Power Co.	AEP	3/31/2016	47.20
North Carolina	Virginia Electric & Power Co.	D	3/31/2016	53.92
New Jersey	Atlantic City Electric Co.	EXC	3/22/2016	49.48
Maine	Emera Maine	EMA	3/21/2016	49.00
Florida	Florida Power & Light Co.	NEE	3/15/2016	45.35
Michigan	Consumers Energy Co.	CMS	3/1/2016	40.75
Missouri	KCP&L Greater Missouri Op Co	GXP	2/23/2016	54.83
Washington	Avista Corp.	AVA	2/19/2016	48.50

Minnesota	Otter Tail Power Co.	OTTR	2/16/2016	52.50
Texas	Southwestern Public Service Co	XEL	2/16/2016	53.97
Michigan	DTE Electric Co.	DTE	2/1/2016	37.49
New York	Consolidated Edison Co. of NY	ED	1/29/2016	48.00
Tennessee	Kingsport Power Company	AEP	1/4/2016	42.43
Oklahoma	Oklahoma Gas and Electric Co.	OGE	12/18/2015	53.31
Virginia	Virginia Electric & Power Co.	D	12/1/2015	49.99
Washington	PacifiCorp	BRK.A	11/25/2015	49.10
Massachusetts	Massachusetts Electric Co.		11/6/2015	51.98
Maryland	Baltimore Gas and Electric Co.	EXC	11/6/2015	53.70
Arizona	Tucson Electric Power Co.	FTS	11/5/2015	50.03
North Dakota	MDU Resources Group Inc.	MDU	10/26/2015	50.27
Missouri	Empire District Electric Co.	AQN	10/16/2015	49.01
New Mexico	Southwestern Public Service Co	XEL	10/16/2015	53.97
Indiana	Northern IN Public Svc Co.	NI	10/1/2015	45.20
Virginia	Virginia Electric & Power Co.	D	10/1/2015	49.99
Virginia	Virginia Electric & Power Co.	D	10/1/2015	49.99
Tennessee	Kingsport Power Company	AEP	9/28/2015	42.43

Michigan	Upper Peninsula Power Co.		9/18/2015	54.13
New Mexico	Public Service Co. of NM	PNM	8/27/2015	49.61
Texas	El Paso Electric Co.	EE	8/10/2015	49.52
Oklahoma	Public Service Co. of OK	AEP	7/1/2015	48.00
Virginia	Virginia Electric & Power Co.	D	7/1/2015	49.99
Virginia	Kentucky Utilities Co.	PPL	6/30/2015	54.07
Montana	MDU Resources Group Inc.	MDU	6/25/2015	49.52
Massachusetts	Fitchburg Gas & Electric Light	UTL	6/16/2015	52.92
Texas	Entergy Texas Inc.	ETR	6/12/2015	50.08
New Mexico	Southwestern Public Service Co	XEL	6/8/2015	53.97
Virginia	Virginia Electric & Power Co.	D	6/1/2015	49.99
Virginia	Virginia Electric & Power Co.	D	6/1/2015	49.99
Virginia	Virginia Electric & Power Co.	D	6/1/2015	49.99
Virginia	Virginia Electric & Power Co.	D	6/1/2015	49.99
Idaho	Avista Corp.	AVA	6/1/2015	50.00
Wisconsin	Northern States Power Co - WI	XEL	5/29/2015	52.59
South Carolina	South Carolina Electric & Gas	SCG	5/29/2015	52.46
New York	NY State Electric & Gas Corp.		5/20/2015	50.00

New York	Rochester Gas & Electric Corp.		5/20/2015	50.00
Mississippi	Mississippi Power Co.	SO	5/15/2015	49.42
New Mexico	El Paso Electric Co.	EE	5/11/2015	49.29
Arizona	UNS Electric Inc.	FTS	5/5/2015	52.83
California	Liberty Utilities CalPeco Ele	AQN	5/1/2015	55.00
Arkansas	Entergy Arkansas Inc.	ETR	4/24/2015	30.16
Illinois	Ameren Illinois	AEE	4/24/2015	50.00
Wisconsin	Wisconsin Public Service Corp.	WEC	4/17/2015	50.52
Illinois	Commonwealth Edison Co.	EXC	4/15/2015	46.25
Pennsylvania	PPL Electric Utilities Corp.	PPL	3/31/2015	51.66
Pennsylvania	PECO Energy Co.	EXC	3/27/2015	53.36
Wyoming	PacifiCorp	BRK.A	3/2/2015	51.44
Kansas	Westar Energy Inc.	WR	3/2/2015	53.12
Oregon	Portland General Electric Co.	POR	2/12/2015	50.00
Washington	Avista Corp.	AVA	2/9/2015	48.00
New York	Consolidated Edison Co. of NY	ED	1/30/2015	48.00
Kansas	Kansas City Power & Light	GXP	1/2/2015	50.48
Indiana	Indianapolis Power & Light Co.	AES	12/29/2014	37.33

Kentucky	Kentucky Power Co.	AEP	12/23/2014	45.19
Texas	Cross Texas Transmission		12/23/2014	45.00
Michigan	DTE Electric Co.	DTE	12/19/2014	38.03
South Dakota	NorthWestern Corp.	NWE	12/19/2014	53.61
New Mexico	Public Service Co. of NM	PNM	12/11/2014	49.60
Texas	Southwestern Public Service Co	XEL	12/8/2014	53.97
Michigan	Consumers Energy Co.	CMS	12/5/2014	41.50
Kentucky	Kentucky Utilities Co.	PPL	11/26/2014	53.02
Kentucky	Louisville Gas & Electric Co.	PPL	11/26/2014	52.75
New York	Orange & Rockland Utlts Inc.	ED	11/14/2014	48.00
Virginia	Virginia Electric & Power Co.	D	10/31/2014	52.03
Missouri	Kansas City Power & Light	GXP	10/30/2014	50.09
Michigan	Wisconsin Public Service Corp.	WEC	10/17/2014	40.82
Missouri	Empire District Electric Co.	AQN	8/29/2014	51.45
Pennsylvania	Metropolitan Edison Co.	FE	8/4/2014	49.96
Pennsylvania	Pennsylvania Electric Co.	FE	8/4/2014	49.90
Pennsylvania	Pennsylvania Power Co.	FE	8/4/2014	50.07
Pennsylvania	West Penn Power Co.	FE	8/4/2014	50.13

New York	Central Hudson Gas & Electric	FTS	7/25/2014	48.00
Missouri	Union Electric Co.	AEE	7/3/2014	51.76
West Virginia	Appalachian Power Co.	AEP	6/30/2014	47.16
Hawaii	Hawaiian Electric Co.	HE	6/27/2014	56.94
South Dakota	Northern States Power Co. - MN	XEL	6/23/2014	53.86
Colorado	Public Service Co. of CO	XEL	6/17/2014	56.00
Virginia	Virginia Electric & Power Co.	D	6/16/2014	52.03
Virginia	Virginia Electric & Power Co.	D	6/16/2014	52.03
Virginia	Virginia Electric & Power Co.	D	6/16/2014	52.03
Virginia	Virginia Electric & Power Co.	D	5/30/2014	52.03
Washington	PacifiCorp	BRK.A	5/1/2014	51.73
West Virginia	Monongahela Power Co.	FE	4/30/2014	46.47
South Dakota	Black Hills Power Inc.	BKH	3/31/2014	53.32
Wyoming	PacifiCorp	BRK.A	3/3/2014	51.43
Oklahoma	Public Service Co. of OK	AEP	1/17/2014	48.69
Minnesota	Northern States Power Co. - MN	XEL	11/4/2013	52.50
Mississippi	Mississippi Power Co.	SO	1/25/2013	49.95
New Jersey	Jersey Cntrl Power & Light Co.	FE	11/30/2012	53.80
			Average	49.92

FTEs, Wages & Salaries 2014-2018

Class	2014 FTE Actuals	2014 W&S Actuals
EXEMPT	1259.3	$127,602,913
HOURLY	464.5	$22,260,633
OFFICER	12.0	$3,849,267
UNION	728.6	$57,716,267
Total	**2464.4**	**$211,429,079**

Class	2015 FTE Actuals	2015 W&S Actuals
EXEMPT	1319.2	$134,990,474
HOURLY	448.4	$21,893,964
OFFICER	12.7	$4,240,599
UNION	721.4	$58,973,989
Total	**2501.7**	**$220,099,026**

Class	2016 FTE Actuals	2016 W&S Actuals
EXEMPT	1404.3	$144,429,273
HOURLY	427.1	$21,713,534
OFFICER	11.9	$4,160,567
UNION	738.0	$62,284,699
Total	**2581.3**	**$232,588,072**

Class	2017 FTE Budget	2017 W&S Budget
EXEMPT	1554.7	$166,526,976
HOURLY	536.1	$29,064,128
OFFICER	12.0	$4,327,004
UNION	814.6	$69,884,477
Total	2917.4	$269,802,585
PGE Prefiling Adjustment	(127.6)	-$10,929,539
Net Total	**2789.8**	**$258,873,046**

Class	2018 FTE Budget	%	Specific Removals	Pro Rata Adjustments	2018 FTE Budget w/Adj.	2018 W&S Budget	2018 W&S Budget w/Adj.
EXEMPT	1612.5	54.1%		(57.5)	1555.1	$177,437,545	$172,032,533
HOURLY	544.2	18.2%	(37.9)	(19.4)	486.9	$30,299,082	$26,712,365
OFFICER	12.0				12.0	$4,478,449	$4,478,449
UNION	826.7	27.7%		(29.5)	797.2	$72,374,081	$69,603,212
Total	2995.4					$284,589,156	
PGE Prefiling Adjustment	(144.2)					-$11,762,597	
Net Total	**2851.1**				**2851.1**	**$272,826,559**	**$272,826,559**

Incentives by Employee Class 2014-2018

Class	2014 Actual	2015 Actual	2016 Actual	2017 Budget	2018 Forecast	2018 Request
Exempt	$ 13,972,345	$ 13,285,524	$ 14,095,754	$ 19,002,624	$ 20,661,392	**$ 10,616,991**
Hourly	$ 1,291,829	$ 1,176,784	$ 1,266,557	$ 2,130,109	$ 2,029,437	**$ 1,059,173**
Officer	$ 5,970,686	$ 6,397,309	$ 6,204,854	$ 7,085,320	$ 7,644,072	**$ 1,237,570**
Union	$ -	$ -				**$ -**
Total	$ 21,234,860	$ 20,859,617	$ 21,567,165	$ 28,218,054	$ 30,334,901	**$ 12,913,734**

Overtime by Employee Class 2014-2018

Class	2014 Actual	2015 Actual	2016 Actual	2017 Budget	2018 Forecast
Hourly	$1,183,492	$1,427,286	$1,199,425	$1,019,097	$1,054,980
Union	$22,405,287	$22,739,437	$23,769,036	$18,546,544	$19,010,442
Exempt	N/A	N/A	N/A	N/A	N/A
Officer	N/A	N/A	N/A	N/A	N/A
Total	**$23,588,779**	**$24,166,722**	**$24,968,461**	**$19,565,641**	**$20,065,422**

April 28, 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. 486
Dated April 14, 2017

Request:

With regard to FTE positions within the entire PGE organization:

a. **What is the total number of FTE positions as of the date of this data request?**
b. **What, if any, is the total number of FTE positions that are being eliminated by December 31, 2018? For each FTE position that will be eliminated, provide best estimate of when the elimination will occur and whether the employee will be reallocated within the company.**
c. **What, if any, are the number of FTE that are being reallocated to the IT/IS organization from other departments?**

Response:

a. As of March 31, 2017, the total number of PGE FTEs[1] reported on a basis comparable with PGE Exhibit 401 is 2,627.47, which is an increase of 46.2 over PGE's FTEs as of December 31, 2016.

b. PGE hires a large number of temporary employees on a consistent annual basis for a wide variety of reasons, including seasonal work, specific project work, and workforce pipeline development (e.g., PGE's summer intern program). The average annual number of temporary positions that PGE has hired from 2014 through 2016 is 208, whereas the average number of temporary FTEs (i.e., full-time equivalents) over the same period is approximately 55. This highlights an important distinction, particularly pronounced for temporary hires: one temporary employee does not equate to one temporary FTE.

[1] One FTE is calculated as the number of straight-time hours worked per position divided by the number straight-time hours during a period of time. From January 1, 2017 through March 31, 2017, this equals 540 hours.

Attachment 486-A, which is protected information and subject to Protective Order No. 17-057, provides all current temporary employees, their estimated end date and if they are in a guaranteed position and will be reallocated to other areas. For employees that will be reallocated, the assumption is that they will move into a comparable position created by former employees retiring or leaving for other reasons and not to incremental positons requested in PGE's 2018 test year forecast.

c. Attachment 486-A includes a column titled "IT", which indicates if PGE expects a guaranteed temporary position to be reallocated to the Information Technology department. As stated in part (b), if a position is to be reallocated, the assumption is that they will move into a comparable position created by former employees retiring or leaving for other reasons and not to incremental positons requested in PGE's 2018 test year forecast.

UE 319

Attachment 486-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Current Temporary Employees as of April 1, 2017

Summary of Other Revenue
Actuals vs Budget/Forecast
2006-2014

	2006			
	Actuals	**Budget**	**Delta**	**Actuals**
Forefeited Discounts	(625,520)	(1,200,000)	(574,480)	(684,364)
Miscellaneous Service Revenues	(1,934,911)	(2,585,915)	(651,004)	(2,723,054)
Sales of Water & Water Power	46,202	-	(46,202)	23,300
Rent From Electric Property	-	-	-	-
RentFrElecProperty-Joint Pole*	(6,434,441)	(6,082,294)	352,147	(5,773,281)
Other Electric Revenues	(275,239)	(145,490)	129,749	(196,475)
OthElecRev-FishWildlifeRecrOps	(16,100)	-	16,100	(14,950)
OthElecRev-SSHG	(292,930)	(265,800)	27,130	(299,211)
OthElecRev-Utility Non-Kwh	(396,864)	(362,000)	34,864	(393,954)
OthElecRev-Steam Sales	(1,506,772)	(1,419,110)	87,662	(1,847,153)
TransRevOthers-Non-Intertie	(1,770,440)	(1,847,152)	(76,712)	(2,713,410)
TransRevOthers-Intertie	(4,056,154)	(3,788,000)	268,154	(4,067,946)
TransOp-IntercoTransStudyRev	-	-	-	-
Sunway	-	-	-	-
Adjustments per final order	-	-	-	-
Totals	(17,263,169)	(17,695,761)	(432,592)	(18,690,500)
Check	-	-	0	-

Notes:
* In 2006 and 2007 Rental Revenue was forecast as a single amount.

2007			2008			2009
Forecast	**Delta**	**Actuals**	**Budget**	**Delta**	**Actuals**	**Forecast**
(1,250,000)	(565,636)	(800,698)	(650,000)	150,698	(785,251)	(650,000)
(2,600,733)	122,321	(3,390,849)	(3,158,924)	231,925	(3,243,313)	(4,418,145)
-	(23,300)	10,068	-	(10,068)	(44,968)	-
-	-	(1,260,730)	(946,145)	314,585	(1,602,886)	(964,771)
(6,082,812)	(309,531)	(4,857,606)	(4,157,997)	699,609	(5,043,634)	(4,057,997)
(145,490)	50,985	(384,890)	(117,200)	267,690	(413,160)	(117,200)
-	14,950	(13,699)	-	13,699	(15,108)	-
(239,800)	59,411	(329,265)	(333,800)	(4,535)	(333,071)	(333,800)
(354,500)	39,454	(404,449)	(487,000)	(82,551)	(492,253)	(487,000)
(1,419,110)	428,043	(2,096,936)	(1,688,339)	408,597	(2,098,201)	(2,413,339)
(1,847,152)	866,258	(2,975,062)	(2,589,800)	385,262	(2,503,692)	(2,215,419)
(3,788,000)	279,946	(4,053,808)	(3,688,000)	365,808	(3,912,478)	(3,688,000)
-	-	-	-	-	-	-
-		-	-		-	-
(1,470,000)	(1,470,000)	-	-	-	-	(455,000)
(19,197,597)	(507,097)	(20,557,924)	(17,817,205)	2,740,718	(20,488,015)	(19,800,671)
-	0	-	-	-	-	-

	2010			2011		
Delta	Actuals	Budget	Delta	Actuals	Forecast	Delta
135,251	(653,441)	(800,000)	(146,559)	(1,854,756)	(2,800,000)	(945,244)
(1,174,832)	(2,184,731)	(1,621,144)	563,587	(2,351,445)	(1,829,880)	521,565
44,968	14,835	-	(14,835)	17,839	-	(17,839)
638,115	(1,604,055)	(1,659,331)	(55,276)	(1,797,125)	(1,659,643)	137,482
985,637	(5,366,933)	(4,530,177)	836,756	(4,966,741)	(4,530,177)	436,564
295,960	(3,270,606)	(2,687,328)	583,278	(3,057,172)	(2,058,582)	998,590
15,108	(12,557)	-	12,557	(17,976)	-	17,976
(729)	(346,613)	(314,400)	32,213	(229,099)	(305,418)	(76,319)
5,253	(99,844)	(480,000)	(380,156)	(34,396)	(478,000)	(443,604)
(315,138)	(1,747,435)	(1,823,808)	(76,373)	(1,695,644)	(2,319,359)	(623,715)
288,273	(1,695,964)	(2,232,544)	(536,580)	(1,565,735)	(1,217,348)	348,387
224,478	(4,021,048)	(3,763,000)	258,048	(4,502,711)	(3,763,000)	739,711
-	(15,585)	-	15,585	(151,992)	-	151,992
	-	-		-	-	
(455,000)	-	-	-	-	(2,078,000)	(2,078,000)
687,344	(21,003,975)	(19,911,732)	1,092,243	(22,206,953)	(23,039,407)	(832,454)
-	-	-	-	-	-	-

2012			2013		
Actuals	**Budget**	**Delta**	**Actuals**	**Budget**	**Delta**
(2,587,422)	(2,200,000)	387,422	(2,758,129)	(2,600,000)	158,129
(2,303,654)	(1,952,992)	350,662	(1,855,439)	(2,044,679)	(189,240)
(4,641)	-	4,641	(14,457)	-	14,457
(1,707,745)	(1,650,506)	57,239	(1,547,136)	(1,599,131)	(51,995)
(5,698,892)	(4,755,310)	943,582	(5,328,476)	(5,286,465)	42,011
(3,123,956)	(2,984,370)	139,586	(3,090,501)	(2,704,345)	386,156
(11,508)	(7,213)	4,295	(13,735)	(16,314)	(2,579)
(229,099)	-	229,099	(174,696)	(222,611)	(47,915)
(654)	(60,000)	(59,346)	(1,068)	(60,000)	(58,933)
(1,688,434)	(2,140,131)	(451,697)	(2,004,226)	(1,614,954)	389,272
(1,840,168)	(1,660,892)	179,276	(2,200,277)	(1,798,892)	401,385
(5,413,152)	(5,225,000)	188,152	(5,488,767)	(5,005,000)	483,767
(5,091)	-	5,091	(116,809)	-	116,809
-	-		-	-	
-	-	-	-	-	-
(24,614,416)	(22,636,414)	1,978,002	(24,593,716)	(22,952,390)	1,641,325
-	-	-	-	-	-

2014			2015		
Actuals	**Forecast**	**Delta**	**Actuals**	**Forecast**	**Delta**
(3,092,995)	(2,600,000)	492,995	(3,019,107)	(2,900,000)	119,107
(1,716,285)	(2,291,099)	(574,814)	(1,796,073)	(1,999,009)	(202,936)
27,627	-	(27,627)	22,164	-	(22,164)
(1,302,935)	(1,227,175)	75,760	(1,043,393)	(1,307,411)	(264,018)
(6,180,231)	(5,286,465)	893,767	(6,564,797)	(5,739,806)	824,991
(3,378,748)	(2,547,345)	831,404	(3,487,297)	(3,064,835)	422,462
(15,168)	-	15,168	(19,493)	(16,594)	2,899
(283,870)	(88,317)	195,553	(239,360)	(174,684)	64,676
(1,566)	(60,000)	(58,435)	(2,657)	-	2,657
(2,494,638)	(1,614,954)	879,684	(2,555,480)	(1,833,767)	721,713
(2,344,157)	(1,311,342)	1,032,814	(2,971,892)	(1,361,294)	1,610,598
(5,683,073)	(4,355,000)	1,328,073	(5,285,337)	(5,110,000)	175,337
-	-	-	-	-	-
-	(14,000)	(14,000)	-	(13,225)	(13,225)
-	(749,000)	(749,000)	-	(2,277,000)	(2,277,000)
(26,466,038)	(22,144,697)	4,321,341	(26,962,722)	(25,797,625)	1,165,097
-	-	-	-	-	-

2016		
Actuals	Forecast	Delta
(2,994,617)	(3,400,000)	(405,383)
(1,852,377)	(1,898,601)	(46,224)
24,166	-	(24,166)
(1,025,319)	(1,225,341)	(200,022)
(7,679,162)	(5,926,522)	1,752,640
(3,648,451)	(2,999,738)	648,712
(12,386)	13,209	25,595
(69,475)	(135,000)	(65,525)
(2,478)	-	2,478
(1,480,085)	(2,487,289)	(1,007,204)
(2,899,444)	(1,748,125)	1,151,319
(5,080,702)	(5,331,000)	(250,298)
-	-	-
-	-	-
-	(1,500,000)	(1,500,000)
(26,720,329)	(26,638,408)	81,921
-	-	-

Other Revenue
Actuals vs Budget/Forecast
2010-2014

Account	Category	Actuals	Remove Oil Resale
4500001	Forefeited Discounts	$ (653,441)	
4510001	Miscellaneous Service Revenues	$ (2,184,731)	
4530001	Sales of Water & Water Power	$ 14,835	
4540001	Rent From Electric Property	$ (1,604,055)	
4540002	RentFrElecProperty-Joint Pole	$ (5,366,933)	
4560001	Other Electric Revenues	$ (8,418,028)	$ 5,147,422
4560003	OthElecRev-FishWildlifeRecrOps	$ (12,557)	
4560004	OthElecRev-SSHG	$ (346,613)	
4560005	OthElecRev-Utility Non-Kwh	$ (99,844)	
4560012	OthElecRev-Steam Sales	$ (1,747,435)	
4561001	TransRevOthers-Non-Intertie	$ (1,695,964)	
4561002	TransRevOthers-Intertie	$ (4,021,048)	
5600003	TransOp-IntercoTransStudyRev	$ (15,585)	
	Sunway	$ -	
	Adjustments per final order		
	Totals	(26,151,397)	5,147,422
	total delta (2008-2016)	12,875,538	
	average delta	1,430,615.34	

2010				2011	
	Adjusted Actuals	Budget	Delta	Actuals	Forecast
$	(653,441)	(800,000)	(146,559)	(1,854,756)	(2,800,000)
$	(2,184,731)	(1,621,144)	563,587	(2,351,445)	(1,829,880)
$	14,835	-	(14,835)	17,839	-
$	(1,604,055)	(1,659,331)	(55,276)	(1,797,125)	(1,659,643)
$	(5,366,933)	(4,530,177)	836,756	(4,966,741)	(4,530,177)
$	(3,270,606)	(2,687,328)	583,278	(3,057,172)	(2,058,582)
$	(12,557)	-	12,557	(17,976)	-
$	(346,613)	(314,400)	32,213	(229,099)	(305,418)
$	(99,844)	(480,000)	(380,156)	(34,396)	(478,000)
$	(1,747,435)	(1,823,808)	(76,373)	(1,695,644)	(2,319,359)
$	(1,695,964)	(2,232,544)	(536,580)	(1,565,735)	(1,217,348)
$	(4,021,048)	(3,763,000)	258,048	(4,502,711)	(3,763,000)
$	(15,585)	-	15,585	(151,992)	-
$	-	-	-	-	-
$	-		-		(2,078,000)
	(21,003,975)	(19,911,732)	1,092,243	(22,206,953)	(23,039,407)

				20
Delta	Actuals	Correct Steam Sales	Adjust LGIP	Adjusted Actuals
(945,244)	(2,587,422)			(2,587,422)
521,565	(2,303,654)			(2,303,654)
(17,839)	(4,641)			(4,641)
137,482	(1,707,745)			(1,707,745)
436,564	(5,698,892)			(5,698,892)
998,590	(3,838,937)	632,853	82,128	(3,123,956)
17,976	(11,508)			(11,508)
(76,319)	(229,099)			(229,099)
(443,604)	(654)			(654)
(623,715)	(1,055,581)	(632,853)		(1,688,434)
348,387	(1,840,168)			(1,840,168)
739,711	(5,413,152)			(5,413,152)
151,992	(5,091)			(5,091)
-	-			-
(2,078,000)				-
(832,454)	(24,696,544)	-	82,128	(24,614,416)

12				
Budget	Correct Steam Sales	Adjusted Budget	Delta	Actuals
(2,200,000)		(2,200,000)	387,422	(2,758,129)
(1,952,992)		(1,952,992)	350,662	(1,855,439)
-		-	4,641	(14,457)
(1,650,506)		(1,650,506)	57,239	(1,547,136)
(4,755,310)		(4,755,310)	943,582	(5,328,476)
(5,124,501)	2,140,131	(2,984,370)	139,586	(3,355,510)
(7,213)		(7,213)	4,295	(13,735)
-		-	229,099	(174,696)
(60,000)		(60,000)	(59,346)	(1,068)
-	(2,140,131)	(2,140,131)	(451,697)	(2,004,226)
(1,660,892)		(1,660,892)	179,276	(2,200,277)
(5,225,000)		(5,225,000)	188,152	(5,488,767)
-		-	5,091	(116,809)
-		-	-	-
		-	-	
(22,636,414)	-	(22,636,414)	1,978,002	(24,858,725)

2013					
Adjust LGIP	**Adjusted Actuals**	**Budget**	**Delta**		**Actuals**
	(2,758,129)	$ (2,600,000)	158,129		(3,092,995)
	(1,855,439)	$ (2,044,679)	(189,240)		(1,716,285)
	(14,457)	$ -	14,457		27,627
	(1,547,136)	$ (1,599,131)	(51,995)		(1,302,935)
	(5,328,476)	$ (5,286,465)	42,011		(6,180,231)
265,009	(3,090,501)	$ (2,704,345)	386,156		(4,538,748)
	(13,735)	$ (16,314)	(2,579)		(15,168)
	(174,696)	$ (222,611)	(47,915)		(283,870)
	(1,068)	$ (60,000)	(58,933)		(1,566)
	(2,004,226)	$ (1,614,954)	389,272		(2,494,638)
	(2,200,277)	$ (1,798,892)	401,385		(2,344,157)
	(5,488,767)	$ (5,005,000)	483,767		(5,683,073)
	(116,809)	$ -	116,809		-
	-	$ -	-		-
	-		-		
265,009	(24,593,716)	(22,952,390)	1,641,325		(27,626,038)

2014				2015	
Less BPA Pmt	**Adjusted Actuals**	**Forecast**	**Delta**	**Actuals**	**Forecast**
	(3,092,995)	$ (2,600,000)	492,995	(3,019,107)	(2,900,000)
	(1,716,285)	$ (2,291,099)	(574,814)	(1,796,073)	(1,999,009)
	27,627	$ -	(27,627)	22,164	-
	(1,302,935)	$ (1,227,175)	75,760	(1,043,393)	(1,307,411)
	(6,180,231)	$ (5,286,465)	893,767	(6,564,797)	(5,739,806)
1,160,000	(3,378,748)	$ (2,547,345)	831,404	(3,487,297)	(3,064,835)
	(15,168)	$ -	15,168	(19,493)	(16,594)
	(283,870)	$ (88,317)	195,553	(239,360)	(174,684)
	(1,566)	$ (60,000)	(58,435)	(2,657)	-
	(2,494,638)	$ (1,614,954)	879,684	(2,555,480)	(1,833,767)
	(2,344,157)	$ (1,311,342)	1,032,814	(2,971,892)	(1,361,294)
	(5,683,073)	$ (4,355,000)	1,328,073	(5,285,337)	(5,110,000)
	-	$ -	-	-	-
	-	$ (14,000)	(14,000)	-	(13,225)
		$ (749,000)	(749,000)		(2,277,000)
1,160,000	(26,466,038)	(22,144,697)	4,321,341	(26,962,722)	(25,797,625)

	2016		
Delta	Actuals	2016 Test Year	Delta
119,107	(2,994,617)	(3,400,000)	(405,383)
(202,936)	(1,852,377)	(1,898,601)	(46,224)
(22,164)	24,166	-	(24,166)
(264,018)	(1,025,319)	(1,225,341)	(200,022)
824,991	(7,679,162)	(5,926,522)	1,752,640
422,462	(3,648,451)	(2,999,738)	648,712
2,899	(12,386)	13,209	25,595
64,676	(69,475)	(135,000)	(65,525)
2,657	(2,478)	-	2,478
721,713	(1,480,085)	(2,487,289)	(1,007,204)
1,610,598	(2,899,444)	(1,748,125)	1,151,319
175,337	(5,080,702)	(5,331,000)	(250,298)
-	-	-	-
(13,225)			-
(2,277,000)		(1,500,000)	(1,500,000)
1,165,097	(26,720,329)	(26,638,408)	81,921

Other Revenue
Actuals vs Budget/Forecast
2006-2009

			2006			2007	
			Actuals	Budget	Delta	Actuals	Forecast
Late Payment Interest	450	M38111	(625,520)	(1,200,000)	(574,480)	(684,364)	(1,250,000)
Misc. Service Revenue	451	M31111	(1,393,724)	(2,585,915)	(1,192,191)	(1,654,594)	(2,600,733)
Sales of Water & Water Power	453	M32111	46,202	-	(46,202)	23,300	
Property Rents - Supply Energy	454	M33511	(29,531)		29,531	(27,829)	
Rental Rev - Utility Op Prop	454	M33111	(37,527)		37,527	(37,542)	
Joint Pole Revenue	454	M33711	(4,916,638)	(6,082,294)	(1,165,656)	(4,481,485)	(6,082,812)
Transformer Rentals	454	M33731	(517,140)		517,140	(511,543)	
Rent from Electric Prop	454	M33811	(639,111)		639,111	(668,250)	
Coal Car Rentals	454	M33571	(294,494)	-	294,494	(46,632)	
Other Misc Electric Revenues	456	M34191	(531,654)		531,654	(1,050,716)	
Misc Physical Revenues	456	M34819	(191,418)	(145,490)	45,928	(196,475)	(145,490)
Steam Sale Revenues	456	M34189	(1,506,772)	(1,419,110)	87,662	(1,847,153)	(1,419,110)
Fish/Wildlife & Rec Facility	456	M34151	(16,100)		16,100	(14,950)	
Commerce Bank Revenue	456	M34201	-	-	-	-	
Salmon Springs Hosp Grp.	456	M34322	(292,930)	(265,800)	27,130	(299,211)	(239,800)
Rev - Utility Non-KWh Prog	456	M34411	(396,864)	(362,000)	34,864	(393,954)	(354,500)
Misc Rev - Supply Energy	456	M34511	(83,822)	-	83,822	-	
Service Fees - ESS	456	M34575	(9,440)		9,440	(17,715)	
Late Payment Int - ESS	456	M34577	(93)		93	(29)	
Non Intertie - Trans for Others	456	M34581	(447,819)	(1,847,152)	(1,399,333)	-	(1,847,152)
Non Intertie - Trans for Others	456.1	M34591	(1,322,621)		1,322,621	(2,713,410)	
Intertie - Trans for Others	456	M34681	(1,028,231)	(3,788,000)	(2,759,769)	-	(3,788,000)
Intertie - Trans for Others	456.1	M34691	(3,027,922)		3,027,922	(4,067,946)	
Adjustments per final order					-		(1,470,000)
			(17,263,169)	(17,695,761)	(432,592)	(18,690,500)	(19,197,597)

	2008			2009		
Delta	**Actuals**	**Budget**	**Delta**	**Actuals**	**Forecast**	**Delta**
(565,636)	(800,698)	(650,000)	150,698	(785,251)	(650,000)	135,251
(946,139)	(1,788,854)	(1,721,144)	67,710	(1,801,406)	(2,619,552)	(818,146)
(23,300)	10,068	-	(10,068)	(44,968)	-	44,968
27,829	(32,649)	-	32,649	(38,908)	-	38,908
37,542	(37,430)	-	37,430	(37,370)	-	37,370
(1,601,327)	(4,787,527)	(4,157,997)	629,530	(4,967,356)	(4,057,997)	909,359
511,543	(510,715)	(521,200)	(10,485)	(549,080)	(521,200)	27,880
668,250	(750,015)	(424,945)	325,070	(1,053,806)	(443,571)	610,235
46,632	-	-	-	-	-	-
1,050,716	(1,589,202)	(1,428,880)	160,322	(1,431,230)	(1,789,693)	(358,463)
50,985	(167,308)	(117,200)	50,108	(167,867)	(117,200)	50,667
428,043	(2,096,936)	(1,688,339)	408,597	(2,098,201)	(2,413,339)	(315,138)
14,950	(13,699)	-	13,699	(15,108)	-	15,108
-	(217,582)	-	217,582	(245,293)	-	245,293
59,411	(329,265)	(333,800)	(4,535)	(333,071)	(333,800)	(729)
39,454	(404,449)	(487,000)	(82,551)	(492,253)	(487,000)	5,253
-	-	-	-	-	-	-
17,715	(12,394)	(8,900)	3,494	(10,677)	(8,900)	1,777
29	(398)	-	398	-	-	-
(1,847,152)	-	-	-	-	-	-
2,713,410	(2,975,062)	(2,589,800)	385,262	(2,503,692)	(2,215,419)	288,273
(3,788,000)	-	-	-	-	-	-
4,067,946	(4,053,808)	(3,688,000)	365,808	(3,912,478)	(3,688,000)	224,478
(1,470,000)			-		(455,000)	(455,000)
(507,097)	(20,557,924)	(17,817,205)	2,740,718	(20,488,015)	(19,800,671)	687,344

	2010		
	Actuals	Budget	Delta
Forefeited Discounts	(653,441)	(800,000)	(146,559)
Miscellaneous Service Revenues	(2,184,731)	(1,621,144)	563,587
Sales of Water & Water Power	14,835	-	(14,835)
Rent From Electric Property	(1,604,055)	(1,659,331)	(55,276)
RentFrElecProperty-Joint Pole*	(5,366,933)	(4,530,177)	836,756
Other Electric Revenues	(3,270,606)	(2,687,328)	583,278
OthElecRev-FishWildlifeRecrOps	(12,557)	-	12,557
OthElecRev-SSHG	(346,613)	(314,400)	32,213
OthElecRev-Utility Non-Kwh	(99,844)	(480,000)	(380,156)
OthElecRev-Steam Sales	(1,747,435)	(1,823,808)	(76,373)
TransRevOthers-Non-Intertie	(1,695,964)	(2,232,544)	(536,580)
TransRevOthers-Intertie	(4,021,048)	(3,763,000)	258,048
TransOp-IntercoTransStudyRev	(15,585)	-	15,585
Sunway	-	-	
Adjustments per final order	-	-	-
Totals	(21,003,975)	(19,911,732)	1,092,243

RentFrElecProperty-Joint Pole	836,756
TransRevOthers-Intertie	258,048
Offsetting variances	(2,561)

Revenue variance was related to wireless activity. PGE brought a lot of sites on-line in 2010 at activity levels that were much higher than anticipated. This led to significantly more make-ready revenue than was budgeted, as well as an increase in wireless rent. PGE was not privy to licensee forecasts for wireless, so we had no basis to forecast at that level.

Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.

	2011		
	Actuals	Forecast	Delta
Forefeited Discounts	(1,854,756)	(2,800,000)	(945,244)
Miscellaneous Service Revenues	(2,351,445)	(1,829,880)	521,565
Sales of Water & Water Power	17,839	-	(17,839)
Rent From Electric Property	(1,797,125)	(1,659,643)	137,482
RentFrElecProperty-Joint Pole*	(4,966,741)	(4,530,177)	436,564
Other Electric Revenues	(3,057,172)	(2,058,582)	998,590
OthElecRev-FishWildlifeRecrOps	(17,976)	-	17,976
OthElecRev-SSHG	(229,099)	(305,418)	(76,319)
OthElecRev-Utility Non-Kwh	(34,396)	(478,000)	(443,604)
OthElecRev-Steam Sales	(1,695,644)	(2,319,359)	(623,715)
TransRevOthers-Non-Intertie	(1,565,735)	(1,217,348)	348,387
TransRevOthers-Intertie	(4,502,711)	(3,763,000)	739,711
TransOp-IntercoTransStudyRev	(151,992)	-	151,992
Sunway	-	-	-
Adjustments per final order	-	(2,078,000)	(2,078,000)
Totals	(22,206,953)	(23,039,407)	(832,454)

RentFrElecProperty-Joint Pole	436,564
Other Electric Revenues	998,590
Offsetting variances	(189,608)

Revenue variance was related to additional wireless activity, leading to more make-ready revenue than was budgeted, as well as an increase in wireless rent. PGE was not privy to licensee forecasts for wireless, so we had no basis to forecast at that level.

Expected revenues for the Energy Trust Energy Efficiency Contract are based on estimates that come from the Energy Trust of Oregon (ETO). In addition, the final expected revenues per the contract amendments with the ETO are not completed until the month prior to the new year; thus the 2011 increase in revenues was not determined and signed off on by the ETO until the end of 2010. The 2011 revenue budget, however, was estimated in mid 2010.

	2012		
	Actuals	Budget	Delta
Forefeited Discounts	(2,587,422)	(2,200,000)	387,422
Miscellaneous Service Revenues	(2,303,654)	(1,952,992)	350,662
Sales of Water & Water Power	(4,641)	-	4,641
Rent From Electric Property	(1,707,745)	(1,650,506)	57,239
RentFrElecProperty-Joint Pole*	(5,698,892)	(4,755,310)	943,582
Other Electric Revenues	(3,123,956)	(2,984,370)	139,586
OthElecRev-FishWildlifeRecrOps	(11,508)	(7,213)	4,295
OthElecRev-SSHG	(229,099)	-	229,099
OthElecRev-Utility Non-Kwh	(654)	(60,000)	(59,346)
OthElecRev-Steam Sales	(1,688,434)	(2,140,131)	(451,697)
TransRevOthers-Non-Intertie	(1,840,168)	(1,660,892)	179,276
TransRevOthers-Intertie	(5,413,152)	(5,225,000)	188,152
TransOp-IntercoTransStudyRev	(5,091)	-	5,091
Sunway	-	-	
Adjustments per final order	-	-	-
Totals	(24,614,416)	(22,636,414)	1,978,002

Forefeited Discounts	387,422
RentFrElecProperty-Joint Pole*	943,582
OthElecRev-SSHG	229,099
TransRevOthers-Non-Intertie	179,276
TransRevOthers-Intertie	188,152
Offsetting variances	50,470

Variance Explanation

2012 is the first full year with AMI in place and the preferred billing cycle benefit available for customers. The forecast was a projected increase based on the estimated impact from AMI.
In 2012, attachment activity throughout the year picked up considerably (which was not projected at time of budget). This led to significantly more make-ready revenue than was budgeted, as well as an increase in pole attachment rental revenue.
PGE does not budget Salmon Springs Hospitality in Other Revenue but does include it in test year forecasts as an adjusting item.
ESS revenues exceeded projections because the direct access window was in November 2011 whereas the 2012 budget was developed in mid-2011.
Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.

	2013		
	Actuals	Budget	Delta
Forefeited Discounts	(2,758,129)	(2,600,000)	158,129
Miscellaneous Service Revenues	(1,855,439)	(2,044,679)	(189,240)
Sales of Water & Water Power	(14,457)	-	14,457
Rent From Electric Property	(1,547,136)	(1,599,131)	(51,995)
RentFrElecProperty-Joint Pole*	(5,328,476)	(5,286,465)	42,011
Other Electric Revenues	(3,090,501)	(2,704,345)	386,156
OthElecRev-FishWildlifeRecrOps	(13,735)	(16,314)	(2,579)
OthElecRev-SSHG	(174,696)	(222,611)	(47,915)
OthElecRev-Utility Non-Kwh	(1,068)	(60,000)	(58,933)
OthElecRev-Steam Sales	(2,004,226)	(1,614,954)	389,272
TransRevOthers-Non-Intertie	(2,200,277)	(1,798,892)	401,385
TransRevOthers-Intertie	(5,488,767)	(5,005,000)	483,767
TransOp-IntercoTransStudyRev	(116,809)	-	116,809
Sunway	-	-	
Adjustments per final order	-	-	-
Totals	(24,593,716)	(22,952,390)	1,641,325

Other Electric Revenues	386,156
OthElecRev-Steam Sales	389,272
TransRevOthers-Non-Intertie	401,385
TransRevOthers-Intertie	483,767
Offsetting variances	(19,255)

Variance Explanation

Expected revenues for the Energy Trust Energy Efficiency Contract are based on estimates that come from the Energy Trust of Oregon (ETO). In addition, the final expected revenues per the contract amendments with the ETO are not completed until the month prior to the new year; thus the 2013 increase in revenues was not determined and signed off on by the ETO until the end of 2012. The 2013 revenue budget, however, was estimated in mid 2012.

Recreation area visitation and subsequent revenue is very dependent on weather, which can result in revenues being higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake. In 2013, this uncertainty resulted in a Park Revenues exceeding budget by $157k

In 2013, Collins Lumber brought on their second kiln ahead of schedule, combined with Columbia River's Whey plant surpassing demand expectations drove revenues beyond budget.

ESS revenues exceeded projections because the direct access window was in November 2012 whereas the 2013 budget was developed in mid-2012.

Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.

	2014		
	Actuals	Budget	Delta
Forefeited Discounts	(3,092,995)	(2,600,000)	492,995
Miscellaneous Service Revenues	(1,716,285)	(2,291,099)	(574,814)
Sales of Water & Water Power	27,627	-	(27,627)
Rent From Electric Property	(1,302,935)	(1,227,175)	75,760
RentFrElecProperty-Joint Pole*	(6,180,231)	(5,286,465)	893,767
Other Electric Revenues	(3,378,748)	(2,547,345)	831,404
OthElecRev-FishWildlifeRecrOps	(15,168)	-	15,168
OthElecRev-SSHG	(148,901)	(88,317)	60,584
OthElecRev-Utility Non-Kwh	(1,566)	(60,000)	(58,435)
OthElecRev-Steam Sales	(2,494,638)	(1,614,954)	879,684
TransRevOthers-Non-Intertie	(2,344,157)	(1,311,342)	1,032,814
TransRevOthers-Intertie	(5,683,073)	(4,355,000)	1,328,073
TransOp-IntercoTransStudyRev	-	-	-
Sunway	-	(14,000)	(14,000)
Adjustments per final order	-	(749,000)	(749,000)
Totals	(26,331,069)	(22,144,697)	4,186,372

RentFrElecProperty-Joint Pole*	893,767

Other Electric Revenues	831,404
OthElecRev-Steam Sales	879,684
TransRevOthers-Non-Intertie	1,032,814
TransRevOthers-Intertie	1,328,073
Offsetting variances	(30,370)

Variance Explanation

For 2014 and 2015 forecasting, PGE based anticipated pole attachment rent on certain licensees receiving the reduced rental rate (RRR). This was based on their historical RRR status as well as projections that we had with regard to their status at the time of forecasting. Some of PGE's largest licensees did not end up qualifying for the reduced rate in both 2014 and 2015, resulting in them paying between $1.50 to $1.75 more per attachment than initially forecast.

PGE is not privy to licensee forecasts for wireless activity and typically cannot anticipate activity increases until they start occurring. Due to technological improvements, wireless activity has significantly increased over the last few years, especially during 2014-2015. In addition to new wireless sites in the years in question (and the resulting make-ready revenue), modifications to existing sites resulted in higher annual rental amounts collected, and higher rental escalations for subsequent years than anticipated.

Energy Trust Energy Efficiency Contract ($625k) - The expected revenues are based on estimates that come from the Energy Trust of Oregon. In addition, the final expected revenues per the contract ammendments with Energy Trust and not completed until the month prior to the new year; thus the 2014 expected revenues were not determined and signed off on by the ETO until the end of 2013. The revenue for the 2014 test year forecast, however, was estimated in late 2012. At the end of 2013 when the ETO provided their final expected revenues in the contract ammendment for 2014, the expected revenues were significantly higher than estimated when the 2014 forecast was being developed in late 2012.

Park Revenues ($220k) - Recreation area visitation and subsequent revenue is very dependent on weather. The summers of 2014 and 2015 set attendance records for several recreation areas around the state, due to record setting temperatures that drew visitors to water based parks and campgrounds. Ultimately, revenues can be higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake.

In 2014, steam customers exceeded budgeted demand. ConAgra finished their plant expansion but had poor operational results from their own auxilary boiler, leading to higher than expected steam demands. In addition, Columbia River's and Collins' had a successful new product launch that led to increased steam demands.

ESS revenues exceeded projections because the direct access window was in November 2013 whereas the 2014 budget was developed in mid-2013.

Intertie revenues exceeded budget due to: 1) the transfer of the Bank of America Leasing share of intertie to PGE in early 2014 (budget prepared in mid 2013), and 2) an increase in non-firm tansmission sales greater than expected.

	2015		
	Actuals	**Budget**	**Delta**
Forefeited Discounts	(3,019,107)	(2,900,000)	119,107
Miscellaneous Service Revenues	(1,796,073)	(1,999,009)	(202,936)
Sales of Water & Water Power	22,164	-	(22,164)
Rent From Electric Property	(1,043,393)	(1,307,411)	(264,018)
RentFrElecProperty-Joint Pole*	(6,564,797)	(5,739,806)	824,991
Other Electric Revenues	(3,487,297)	(3,064,835)	422,462
OthElecRev-FishWildlifeRecrOps	(19,493)	(16,594)	2,899
OthElecRev-SSHG	(239,360)	(174,684)	64,676
OthElecRev-Utility Non-Kwh	(2,657)	-	2,657
OthElecRev-Steam Sales	(2,555,480)	(1,833,767)	721,713
TransRevOthers-Non-Intertie	(2,971,892)	(1,361,294)	1,610,598
TransRevOthers-Intertie	(5,285,337)	(5,110,000)	175,337
TransOp-IntercoTransStudyRev	-	-	-
Sunway	-	(13,225)	(13,225)
Adjustments per final order	-	(2,277,000)	(2,277,000)
Totals	(26,962,722)	(25,797,625)	1,165,097

RentFrElecProperty-Joint Pole*	824,991
Other Electric Revenues	422,462

OthElecRev-Steam Sales	721,713
TransRevOthers-Non-Intertie	1,610,598
Offsetting variances	(137,667)

Variance Explanation

For 2014 and 2015 forecasting, PGE based anticipated pole attachment rent on certain licensees receiving the reduced rental rate (RRR). This was based on their historical RRR status as well as projections that we had with regard to their status at the time of forecasting. Some of PGE's largest licensees did not end up qualifying for the reduced rate in both 2014 and 2015, resulting in them paying between $1.50 to $1.75 more per attachment than initially forecast.

PGE is not privy to licensee forecasts for wireless activity and typically cannot anticipate activity increases until they start occurring. Due to technological improvements, wireless activity has significantly increased over the last few years, especially during 2014-2015. In addition to new wireless sites in the years in question (and the resulting make-ready revenue), modifications to existing sites resulted in higher annual rental amounts collected, and higher rental escalation than anticipated.

Park Revenues ($226k) - Recreation area visitation and subsequent revenue is very dependent on weather. The summers of 2014 and 2015 set attendance records for several recreation areas around the state, due to record setting temperatures that drew visitors to water based parks and campgrounds. Ultimately, revenues can be higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake.

P-Card Rebate ($175k) - In 2015, PGE signed a five-year contract with Bank of America (BoA) for use of employee credit cards (Procurement Cards or P-Card). In signing this five-year contract PGE recieved a $175k signing bonus. This was not captured in the budget as the agreement of the signing bonus was determined through negotiations with BoA after PGE's budgets for 2015 had already been finalized.

In 2015, the price per thousand pounds ($/Klbs) of steam was higher than projected. In addition, the customer Columbia River's and Collin's new product launch successes from 2014 continued and their demand for steam remained stronger than expected.
ESS revenues exceeded projections because the direct access window was in November 2014 whereas the 2015 budget was developed in mid-2014.

	2016		
	Actuals	Budget	Delta
Forefeited Discounts	(2,994,617)	(3,400,000)	(405,383)
Miscellaneous Service Revenues	(1,852,377)	(1,898,601)	(46,224)
Sales of Water & Water Power	24,166	-	(24,166)
Rent From Electric Property	(1,025,319)	(1,225,341)	(200,022)
RentFrElecProperty-Joint Pole*	(7,679,162)	(5,926,522)	1,752,640
Other Electric Revenues	(3,648,451)	(2,999,738)	648,712
OthElecRev-FishWildlifeRecrOps	(12,386)	13,209	25,595
OthElecRev-SSHG	(69,475)	(135,000)	(65,525)
OthElecRev-Utility Non-Kwh	(2,478)	-	2,478
OthElecRev-Steam Sales	(1,480,085)	(2,487,289)	(1,007,204)
TransRevOthers-Non-Intertie	(2,899,444)	(1,748,125)	1,151,319
TransRevOthers-Intertie	(5,080,702)	(5,331,000)	(250,298)
TransOp-IntercoTransStudyRev	-	-	-
Sunway	-	-	-
Adjustments per final order	-	(1,500,000)	(1,500,000)
Totals	(26,720,329)	(26,638,408)	81,921

RentFrElecProperty-Joint Pole	1,752,640
Offsetting variances	(170,719)

PGE received $1.3 million in revenue from a short-term project that entailed the following aspects:
• PGE filed its 2016 general rate case in February 2015.
• The external party gave notice of the project in the summer of 2015.
• PGE and the external party agreed to proceed with the project in January 2016. At that time, PGE expected costs and revenues to equal and offset each other.
• During 2016, the external party did not achieve the volume of projected activity but was obligated to pay the full amount of revenue based on the terms of the contract.
• The external party cancelled the contract near the end of 2016.

PGE also received approximately $0.4 million in 2016 for a joint inspection recovery pilot. This revenue offset the increase in both quantity and scope of inspections performed as part of the pilot. Because this was a pilot program, PGE did not have a basis for including an amount in the 2016 budget.

Finally, PGE had a $0.1 million increase in revenue from permit processing, interim rent, sanctions, and violations charged to licensees for joint use activity, as well as additional wireless applications and site make-ready activity

UE 319 – CERTIFICATE OF SERVICE

I hereby certify that, on this 16th day of June, I served the foregoing **CUB Confidential Testimony & Exhibit** in docket UE 319 upon the Commission and each party designated to receive confidential information pursuant to Order 17-057 by U.S. mail, postage prepaid.

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