BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

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In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision	)
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OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 11, 2014

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I. Introduction

Portland General Electric ("PGE") filed this docket in February. PGE is seeking a series of rate increases in 2015: a small rate hike in January, a larger rate hike when Port Westward 2 comes on line in the first quarter of the year and a third rate hike when Tucannon becomes used and useful somewhere in the first half of the year. In addition, PGE is also asking that certain costs associated with wind be carved out of the PCAM.

In our testimony, CUB will address:

***New Resource Additions.** The three rate changes are driven largely by the two new power supply investments: Port Westward 2 and Tucannon. CUB will discuss the prudence of these investments, as well as CUB's concerns about the premature filing of this rate case and the need for an increase on January 1, 2015.

***RPS Carve Out.** As a party that helped negotiate SB 838, CUB strongly opposes PGE's attempt to reinterpret the agreement that was made at that time. CUB is concerned about the shift in risk associated with market prices that PGE is proposing and believes that there is no evidence that the current PCAM needs to be fixed.

***Energy Efficiency and the Marginal Cost of Service Study.** CUB argues that energy efficiency is a marginal resource and should be included in the marginal cost of service study. However, when that happens parties must account for the fact that different customer classes purchase different quantities of energy efficiency.

***Industrial Energy Efficiency.** PGE is poised to hit the cap on how much industrial energy efficiency it can acquire. CUB believes that by incorporating energy efficiency into the marginal cost of service study, residential and small commercial customers could be permitted to fund additional industrial energy efficiency programs.

The parties have participated in first round settlement negotiations. Some issues have settled in principle, and a partial stipulation is being drafted. CUB, therefore, writes on a limited set of issues in this round of testimony.

II. New Resource Additions.

CUB has previously expressed concerns about utilities who file rate cases well in advance of the completion of major assets but with the expectation that the new asset will be rolled into rates whenever it is finished even if completion ultimately occurs much later than the date the rate case is completed. CUB was and is concerned because such practices create a two-fold problem:

1. The result is often a rate case filed more than a year before the asset comes on line. The longer the time period between the forecast used to set rates and the time that those rates go into effect, the less reliable the forecast. The reduction in reliability of the forecast increases the chance that some costs will have decreased and the utility could have recovered the full cost of the new investment with a smaller rate hike.

2. The more time that falls between the prudence review and the completion of the asset, the less is known about the actual costs of the plant and the Company's management of the construction. Increasingly prudence reviews are becoming more like pre-approvals of the results of the RFP, rather than being a true prudence finding relating to the actual investment in the actual plant.

This docket is a case in point. In this docket, PGE is requesting a rate hike potentially months before its assets will come on line. PGE "expects Tucannon to come on line in the first half of 2015. . . . "[1] Port Westward 2's "planned completion date is the first quarter 2015."[2] By filing in March 2014, PGE is trying to obtain pre-approval for rate increases so as to ensure no regulatory rate lag. It is doing so by attaching the later requested increases to an un-needed January 1 rate hike, a rate hike that has no substance, no real purpose – a rate hike that is completely unneeded.

CUB is concerned that this docket, depending on the order ultimately issued, could result in the establishment of a new precedent permitting an anxious utility to avoid even a day's regulatory lag by filing for an unjustified rate hike so as to obtain preapproval of a project that won't be complete until 6 months after the rate case is over, rather than the utility being required to match the timing of its rate cases with the timing of its investments.

A. Timing of 3 stage rate case.

In this docket, PGE has filed a rate case that envisions, not one, but two additional resources coming on line in the months after the rates have gone into effect in this rate case - this will cause three rate hikes over a period on 6 months.

i. January 1, 2015

The first rate hike, if permitted, will come on January 1, 2015.

> PGE's base business increase request in this case is small. We just completed a 2014 test-year rate case and management has successfully contained costs for this 2015 test-year. PGE's 2014 budget is within $1.6 million, or 0.19%, of the costs included in PGE's 2014 test year prices. The 2014 budget was then escalated for inflation to create the 2015

[1] UE 283 PGE/400/Pope - Lobdell/16
[2] UE 283 / PGE / 400/ Pope - Lobdell / 21

budget, and known changes included. The result is a base business (without the effects of PW2 and Tucannon) increase request of $12.5 million, or 0.7% effective January 1, 2015.[3]

PGE is asking that the first 2015 increase be for less than 0.7%. Much of this 0.7% increase comes from the request to raise PGE's authorized ROE to 10.0% from 9.75%. The 9.75% ROE was only established by the OPUC on December 9, 2013, in Order No. 13-459.[4] This means that the request to increase its ROE to 10.0% came only 9 weeks and 3 days after the Order establishing the current 9.75% ROE. In asking for the increase to 10.0%, PGE claims that the reasonable range for its ROE is between 9.9% and 10.6%.[5] Last year when the OPUC granted the settled 9.75% ROE, PGE had also requested a 10.0% ROE and then it had identified a reasonable range between 10.0% and 10.7%.[6] Today, PGE believes that the reasonable range is slightly below the reasonable range it identified last year, but is nonetheless asking for an increase in ROE.

PGE's requested increase on January 1, 2015 is not justified by the evidence it has presented. It has failed to show that its earnings will not be reasonable on January 1, 2015 and that an increase in rates will be necessary for it to continue to earn a reasonable rate of return. Indeed, it is possible that evidence will be developed, as this case moves forward that will demonstrate that rates should in fact be lowered rather than increased next January.

PGE has failed to make a case for an increase in revenue requirement on January 1, 2015.

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[3] UE 283 - Executive Summary Of Portland General Electric, page 3.
[4] OPUC Order No. 12-459, page 3.
[5] UE 283 PGE/1200/Zepp/41.
[6] UE 262 PGE/1200/Zepp/45.

B. Port Westward 2.

For Port Westward 2, the planned completion date is the first quarter 2015.[7] CUB is, therefore, largely reviewing Port Westward 2 based on its RFP. CUB notes that the RFP projected that in addition to using the plant for peaking capacity, PGE would use the plant's flexibility for wind integration.[8] The Company's testimony shows that the Company is buying wind integration services from BPA.

Port Westward 2 is a new flexible gas plant that is designed to provide "capacity to maintain supply reliability" and to additionally provide "needed flexibility to address variable load requirements and increasing levels of intermittent."[9] In the current AUT, ICNU looked at how Port Westward 2 was modeled in MONET, since it was not being used to integrate renewables:

> Without wind-integration, MONET only models Port Westward II to dispatch in 13 percent of the hours of the year. In contrast, the Capacity RFP assumed Port Westward II would dispatch in 74 percent of hours in 2015. Had the Company modeled Port Westward II solely on economic dispatch, the results of the Capacity RFP likely could have been different. Flexible capacity bids from combined cycle combustion turbine ("CCCT") technologies were not accepted in the Capacity RFP on the basis that they did not meet the Company's flexible capacity needs, yet, because a CCCT has a lower variable cost, it is possible that such a resource would have been selected over Port Westward II if the need to self-integrate wind was not considered. It, therefore, appears that the economics of Port Westward II are dependent on it being used for self- integration.[10]

This is a bit troubling, since the decision to exclude certain technologies was controversial at the time with the Northwest and Intermountain Power Producers Coalition ("NIPPC") arguing that additional technologies should be allowed.[11]

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[7] UE 283 PGE/400/Pope - Lobdell/21.
[8] UM 1535 - Capacity RFP , page 1 (Jan. 25, 2012).
[9] UM 1535, Capacity RFP , page 1 (Jan. 25, 2012).
[10] UE 286 ICNU/100/Mullins/9.
[11] UM 1535 - Comments of the Northwest and Intermountain Power Producers Coalition, page 18.

NIPPC was arguing for the inclusion of unmodified frame simple cycle combustion turbines:

> Since the time PGE began its permitting of its self build option in 2009 employing an aero-derivative turbine, gas turbine manufacturers now offer a commercially viable generation technology which has the same capabilities as aero-derivatives but at a lower cost to rate payers. Recent models of fame unit simple cycle combustion turbines allow for equivalent performance useful for integrating intermittent resources, but at a lower cost than the aero-derivatives.[12]

PGE disagreed with NIPPC, arguing that the frame units NIPPC referred to would not be adequate for integration of variable resources:

> Unmodified frame simple cycle combustion turbines such as that described in footnote 8 of NIPPC's comments are only being commercially used as peaking units. While such units may meet PGE's seasonal peaking needs, there is no certainty that they can provide intra-hour ancillary service needed for load following and integration of variable energy resources.[13]

This is why, when Port Westward 2 does come on line next year, it will do so as a significantly different plant than the one that was proposed in the RFP - it will not be used as to integrate intermittent resources.

PGE is now saying that it will model wind integration benefits in the 4th quarter of 2014 in the AUT's MONET run because PGE expects to shift to self integration at that time.[14]

While timing a new resource addition to coincide with the end of a contract to provide wind integration is in and of itself difficult, it is also not clear that PGE will be able to overcome the difficulties that led it to choose to use a BPA integration service in the first place. If PGE continues to find self-integration too big of a hurdle to get over, it will raise real questions about why the Company assumed at the time of the RFP that it

[12] UM 1535 - Comments of the Northwest and Intermountain Power Producers Coalition, page 17-18.
[13] UM 1535 - Reply Comments of Portland General Electric, page 2.
[14] UE 283 PGE/500/Niman – Peschka – Hager/12.

could/would self-integrate. And ultimately parties will want to examine whether the Company was in error when it issued the RFP, or whether conditions have changed since the RFP.

If Port Westward 2 is not going to be used for integrating renewables for the time being then the Commission should consider disallowing a portion of the rate base that represents the difference between the more expensive flexible resource PGE claimed to need, and the less flexible peaking resource that PGE is actually operating. CUB would like to see PGE provide additional testimony about the intended use of Port Westward 2 for the purposes of integrating intermittent generation.

C. Tucannon

CUB is struggling with what to do with Tucannon. While Tucannon seems like a good resource to meet the requirements of Oregon's RPS, CUB is troubled by the fact that PGE intends to update the capacity factor after the record is complete in this case and that the Company is asking for a prudence determination well before much of the concrete has been poured.

i. The Timing of Tucannon.

While Tucannon may be completed earlier, PGE's testimony makes clear that the Company was expecting it to come into service in the first half of 2015.[15]

Looking at the milestones that PGE has laid out, this project still has a long way to go. From September 2013 to 2014, the Company was building the roads necessary to build the wind turbines.[16] This means that the Company is not expected to finish pouring

[15] UE 283 PGE/400/Pope - Lobdell/14.
[16] UE 283 PGE/400/Pope - Lobdell/16.

the wind turbine foundations until July of this year.[17] And the turbines themselves are not expected to be delivered until sometime this month. This means that when PGE filed this case, the facility was only 20% completed:

> As of January 2014, overall project completion is approximately 20 percent. Approximately 10 miles of roads have been constructed and 25 foundations have been poured and backfilled. Turbine manufacturing is approximately 37 percent complete. A total of 250 blades, 42 hubs, 42 nacelles and 6 towers have been assembled. Deliveries to the site will begin in June 2014.[18]

CUB notes that it did not have to happen this way. PGE could have timed this rate case to be completed when Port Westaward 2 is expected to come on line in the first quarter of the year, which could have put the Tucannon prudence review a couple months later, when the facility is more complete. When the Company filed its rate case at the beginning of February, the Company had yet to begin much of the work necessary to finish the Tucannon facility. Because at the time, neither Port Westward 2 nor Tucannon was expected to be used and useful on January 1st, there was no reason not to wait a month or two, or three and then significant progress could have been made on building the facility.

Tucannon Milestones[19]

Roads	Sept 2013 - Jun 2014
Foundations	Oct 2013 – Jul 2014
Substation	Mar 2014 – Aug 2014
O&M Building	Mar 2014 – Aug 2014
Transmission Line	Mar 2014 – Aug 2014
Turbine Delivery	Jun 2014 – Sept 2014
Turbine Erection	Jun 2014 – Oct 2014
Turbine Commissioning	Aug 2014 – Mar 2015
Interconnection with BPA	December 2014
Initial Operation	First half of 2015
Substantial Completion	First half of 2015

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[17] UE 283 PGE/400/Pope - Lobdell/16.
[18] UE 283 PGE/400/Pope-Lobdell/16.
[19] UE 283 PGE/400/Pope - Lobdell/16.

ii. Capacity Factor

More troubling to CUB is the Company's plan to update the Tucannon capacity factor after the record is closed in this proceeding. The analysis used in the RFP forecasted a capacity factor of 36.8%:

> During PGE's renewable resource Request for Proposals (RFP) process, the Tucannon bid was submitted with a wind study performed by RES Americas. The Independent Evaluator (IE) requested a consultant review all of the wind studies submitted during PGE's renewable resource RFP. The consultant reviewed each study and made adjustments to the energy estimates for various factors in order to provide a standard basis for evaluating each of the studies. The results were then returned to the IE and used as the basis for evaluating the bids submitted. The adjusted energy estimate for Tucannon, based on the consultant's review and adjustments, was 859 GWh per year and a capacity factor of approximately 36.8%.[20]

However, since the RFP, PGE has made changes to the site layout[21] and the Company selected the actual turbines that will be used at the facility.[22] With these changes, PGE has updated its wind integration study and concluded that the capacity factor will in fact be higher - [redacted]%. CUB Exhibit 102 provides the summary table from this most recent study. This study from [redacted] provides the best estimate of the capacity factor of Tucannon before PGE began construction – when the Company made the final decision to go ahead with the project. With this capacity factor, CUB finds the facility to be prudent.

But PGE is not proposing the latest figure as the capacity factor. PGE is proposing to update the capacity factor, this time in October after the record for this proceeding is closed.[23] This is unusual. Capacity factors are not usually updated after a finding of prudence but before there is actual operational experience. In fact the one time

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[20] UE 283 PGE/500/Niman – Peschka – Hager/13.
[21] UE 286 ICNU/103/Mullins/1.
[22] UE 283 PGE/400/Pope - Lobdell/11.
[23] UE 283 PGE/500/Niman – Peschka – Hager/13.

that the Commission found a wind facility to be imprudent, was because of the capacity factor.[24] A prudence review is normally based on what the Company knew at the time it made a decision. The capacity factor that PGE currently expects, which was made [redacted], is the best estimate of what PGE knew at the time it began building the plant. But the desire of the Company to take the unusual step of not using that capacity factor, but updating it after the record is closed, makes CUB suspicious that the Company may hold undisclosed information that would lead it to believe that the capacity factor may in fact, be lower.

CUB supports a finding of prudence using the latest study's capacity factor of [redacted]%. If the Company insists on updating the capacity factor after the record is closed, and using that number as the forecast of Tucannon output, then CUB recommends that the Commission find that it is too early to determine the prudence of the plant. This will allow CUB and other parties to conduct discovery on the post rate case new capacity factor study and find out whether there are items in that study that the Company should have been aware of at the time it made its final decision to construct the facility.

III. Renewable Carve out from PCAM

PGE is proposing to "carve out" from the PCAM mechanism a series of items it says are related to the RPS and recover those on a dollar for dollar basis. PGE provides little justification for its proposal, other than ultimately citing to the statutory language implementing SB 838 which can be found at ORS 469A.120. PGE's testimony reads in part as follows:

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[24] UE 200, Order No. 08-548 - *In the Matter of PACIFICORP, dba PACIFIC POWER 2009 Renewable Adjustment Clause Schedule 202*, 2008 Ore. PUC LEXIS 404 (November 14, 2008).

Enacted in 2007 through Senate Bill 838 (SB 838), codified in ORS 469A, the RPS requires Oregon utilities to deliver a percentage of their electricity from renewable resources. For utilities such as PGE, the percentage of renewables rises periodically until it reaches 25 percent beginning in 2025. PGE's proposal is based on the clear language of SB 838, Section 13, part 1 which states:

"… all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company…"

SB 838 goes on to elaborate on the types of related costs that should also be recoverable:

"…including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity customers."

This language can be found in ORS 469A.120.

Q. Does the current regulatory framework allow for these costs to be fully recovered?

A. No. The current regulatory framework allows for a level of costs and benefits to be included in customer prices as part of a regulatory proceeding such as a general rate case or annual update tariff filing. However, these forecasts often vary significantly from actuals due to uncontrollable circumstances such as weather conditions. For instance, wind generation may be greater than or less than forecasted, reducing or increasing PGE's overall net variable power cost and the amount of production tax credits generated. Additionally, PGE must continue to make investments in renewable resources, such as Tucannon, to maintain compliance with the RPS which will exacerbate the issue with the current regulatory framework.[25]

A. Oregon's RPS Law (SB 838 ORS 469A.120) does not require updating every last factor

PGE knows that SB 838 was never intended to require dollar for dollar recovery of all costs that it can associate with renewable resources. SB 838 was a carefully negotiated piece of legislation. PGE, PacifiCorp, CUB, Renewable Northwest and

[25] UE 283 PGE/500/Niman – Peschka – Hager/43, line 9 to 44, line 9.

several other stakeholders were all at the table and negotiated the language that became the consensus amendments adopted as the basis of the law. PGE may want to change Oregon's policy with regard to PCAM's, and may see renewables as an opportunity to do so, but PGE should not misrepresent the product of prior careful negotiation, if it wants to be able to negotiate with CUB and other stakeholders in the future.

PGE is correct that SB 838 stated that a utility should be allowed to recover prudently incurred costs:

> [A]ll prudently incurred costs *associated with compliance with a renewable portfolio standard* are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers.[26]

CUB explicitly agreed to this language. The prudently incurred items listed above are recoverable in rates. The PUC sets rates on a forward-looking basis, based on forecasted costs. The cited statement from the law was simply intended as reassurance for the utilities that included within the forward looking forecasted costs would be all prudently incurred costs associated with complying with the law. The reference to "above-market costs" is significant, because there was a concern that a party might challenge costs associated with renewable resources because they were above market and therefore not least cost. But under no circumstance was this section of the law intended to imply anything other than the expectation that these costs would be "recoverable in rates" through the normal ratemaking process.

That the costs set forth above were intended only to be recovered in the normal ratemaking process is made clear by the fact that a separate section was created in the law

[26] ORS 469A.120(1) (*emphasis added*).

to deal with certain costs that were identified in the negotiations, and agreed to by CUB, that were recoverable outside of the normal forward looking forecasted ratemaking:

> The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.[27]

CUB agreed, in this instance only, to go outside of the normal ratemaking process and establish an automatic adjustment clause - called the Renewable Adjustment Clause ("RAC") - to allow for recovery of construction and transmission. This allows utilities to avoid regulatory lag. It was not CUB's intent to, and neither did it, agree to such a process for wind forecasting error or wind integration costs. Indeed, the law adopted specifically states that those costs are recoverable in rates, meaning through the normal ratemaking process (and not through an automatic adjustment clause like the RAC).

B. There was a specific purpose to Placing these costs in an Automatic Adjustment Clause

CUB and the other parties to the negotiations recognized the need for n automatic adjustment clause because ratemaking practices at the time created a risk of regulatory lag.

i. At The Time The RPS Was Adopted, Rates in General Rate Cases Went Into Effect on January 1.

PGE and PacifiCorp both had (and still have) annual power cost cases related to direct access. The rates for those power cost cases go into effect on January 1st of each year. At the time the RPS was created, by way of practice, the utilities filed general rate

[27] ORS 469A.120(2).

cases which were designed to also time rate changes for January 1st - this practice was originally adopted to minimize the number of rate changes in a given year. Indeed, for several years there was a requirement in the TAM guidelines that required PacifiCorp to manage general rate cases with a rate effective date of January 1st. Today, however, that requirement has been removed from the PacifiCorp TAM and CUB now encourages utilities to manage rate cases so that the rate effective dates are tied to when new assets come on line, rather than to January 1st. CUB notes that the use of January 1st as the effective date for general rate cases had, contrary to expectation, led to an increase in the number of rate changes and led to multiple changes in base rates each year. This UE 283 docket is an example of that same phenomenon - PGE is today unnecessarily proposing a 3-stage rate case, with a January effective date, within this docket. So, to summarize, while today CUB encourages utilities to match up rate cases with the expected dates of new capital additions so as to avoid multiple rate hikes each year, at the time SB 838 passed the practice was to time all general rate cases for January 1st.

ii. At The Time SB 838 Was Passed The Utilities Ability to Add New Resources Later in the Test Year was Limited.

Today, it is not uncommon for the Commission to allow utilities to add new large assets several months after the rates go into effect. (Note: CUB continues to have concerns about this practice – see page 2 of this testimony). However, at the time of the RPS, the practice of adding resources later in the year was even more controversial. CUB litigated the issue in a 2006 PGE rate case. The order in that case arrived only a couple of months before the RPS negotiations took place. That order stated:

> As PGE agrees, CUB raises a legitimate point as to the validity of the assumptions regarding Port Westward if its opening is delayed. To allow

> flexibility for PGE, we conclude that the decisions made in this consolidated case will prevail, as long as Port Westward becomes operational within 60 days of the estimated March 1, 2007, online date. If Port Westward becomes operational on or after April 30, and before September 1, 2007, Staff and intervenors will have 15 days from the online date to determine whether there is new information that requires a re-examination of PGE's costs in rates. If Port Westward does not become operational until after September 1, 2007, PGE must file an entirely new rate case to add the plant to rate base when it meets the used and useful standard.[28]

iii. The Order Cited Above Created A Risk of Regulatory Lag

The combination of rates being effective January 1st and limits being put on the amount of time that can pass before a new asset is put into rates created a real risk of regulatory lag. Under the precedent of the Order above, if a new renewable resource was to come online in the Fall after the last rate case then the utility could not hitch the new resource to the prior rate case and the utility had to wait until the following January to place the new resource into rates. Making matters worse, if the resource was expected to come on line in the fall, then it was likely that some parties would propose incorporating it into the power cost case (AUT or TAM). This meant that the utility would carry the potential risk of being required to pass through the dispatch benefits before it could recover the capital investment.

When it came time to negotiate the RPS, the potential for such regulatory lag seemed unfair to PGE and PacifiCorp. CUB and the other parties were, therefore, willing to accommodate the utilities' concerns by agreeing to the inclusion of an Automatic Adjustment Clause within the law so as to remove the regulatory lag associated with the new renewable resource capital investments.

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[28] OPUC Order No. 07-015, page 50.

C. Renewables Are Generally Rate Based Assets, So The Company Is Compensated For Managing The Risk That Comes With The Asset.

The net power costs that PGE is seeking to remove from the PCAM in order to receive a dollar-for-dollar recovery derive from generation facilities that are in the Company's rate base. Nearly the entire cost of the generation is capital on which the utility gets a return. In theory, the return is tied to the risk of managing the asset. Natural gas combustion turbines have less rate base and more fuel costs. The utility is getting less return on investment but is managing a fuel cost risk that is subject to the PCAM with its deadband and earnings test. PGE has not demonstrated that the risk/rate base ratio associated with renewables is any different than that of a natural gas plant.

D. Wind Variability vs. Hydro Variability

CUB certainly acknowledges that wind generation comes with a degree of unpredictability that affects PGE's generation portfolio on an hourly basis. Excursions from anticipated levels of wind generation may cause differences in net power costs for periods of hours or days. For hydro utilities, excursions from anticipated levels of precipitation can last for periods of weeks and months. When the Commission established PGE's PCAM, it acknowledged that the normal level of hydro risk was being maintained with the utility:

> We conclude that a PCAM should be adopted to capture power cost variations that exceed those considered part of normal business risk. In this case, normal business risk for PGE includes all of the circumstances to which it is exposed, such as hydro variability.[29]

While the risks associated with wind and solar are different than the risks associated with hydro, PGE has not demonstrated that they are any greater than the risks associated with hydro.

E. PGE's Chosen Mechanism Might Not Work When PGE Self-Integrates.

PGE's chosen mechanism includes the differences between forecasted wind integration costs and actual costs. This is possible under the circumstances of the current wind integration contract between PGE and BPA because PGE can isolate the wind integration costs. But PGE built Port Westward 2 in order to reduce its wind integration costs by self-integrating. Once the Company begins to self-integrate (assuming it does), there are no longer isolated costs associated with wind integration. The Company will be using Port Westward 2, hydro and other resources to integrate the wind. Identifying and tracking which net power costs relate to actual wind integration costs will be nearly impossible. There has been a great deal of consternation in recent years over the wind integration studies utilities have used in IRPs. During PGE's 2009 IRP, CUB had a simple idea to conduct a backcast to see if the actual cost of wind integration matched up with the study – CUB was told this was impossible.[30] But a backcast to compare to a projection is no different than comparing actuals to a forecast. PGE has failed to demonstrate that it is possible once it is self-integrating to identify actual costs of wind integration.

[29] OPUC Order No. 07-015, page 26.
[30] LC 48 - CUB Comments, page 1.

F. PGE's Proposal Updates The Value Of Renewables, Not The Cost Of Renewables

PGE's mechanism goes beyond updating/correcting for wind forecasting errors and wind integration and shifts to customers the risks associated with changes in power prices.

PGE's mechanism is really about the value of renewables, not the cost to the Company of renewables. PGE's Exhibit 503 shows how these variances are calculated. For the wind forecasting (as opposed to royalties and wind integration costs) the formula is simple: The forecasted hourly generation times the forecasted market price is compared to the actual hourly generation times the actual hourly Mid-C Price.[31] The difference is then charged or credited to customers.

The problem with this is that even if the forecasted generation and actual generation show no or little variation, (therefore there is no real difference), the mechanism still can result in a significant surcharge or surcredit associated with the change in market prices, essentially passing through the nominal change in values as a real cost to the customer. Assume an hour where the market price is high enough that PGE is dispatching the full output of Port Westward 1 and 2 and Coyote Springs, but not Beaver and that the wind facilities produce 500 MWh. If the price increases enough, PGE will dispatch Beaver and will receive additional income from selling Beaver into the market (or offsetting market purchases depending on its load during the hour). But that price change will have no impact on the wind generation, it will still be 500 MWh. But under PGE's methodology, a change in price changes the value of the wind and will always lead to a surcharge or surcredit for customers.

[31] UE 283 PGE/503/Niman - Peschka – Hager/1.

PGE may claim that the value of the wind production has changed, which is true, but this has little to do with the wind forecasting error and instead is an error in forecasting market prices.

G. The PCAM Is Not Broken.

PGE is proposing to carve out from the PCAM certain costs related to renewables. But this assumes that there is a problem with the current PCAM. PGE, however, fails to show that the PCAM is systematically failing to provide them full recovery of its power costs. Before fixing a problem, there should be some evidence that the problem exists. But the current methodology of forecasting power costs and truing them up subject to the deadband and earnings test of the PCAM is working.

Staff analyzed the PCAM in UE 286. In that AUT docket, Staff found that there was a systematic over-forecasting of costs to the detriment of the customers. Staff found that the Company was currently over collecting its net power costs:

> Correcting for variations in load, PGE has over-collected for power costs each of the 5 years from 2008 through 2012. PGE uses the term “power cost variance”, or PCV, to refer to the difference between power costs collected through rates and actual power costs incurred by the Company. In the table, the annual PCV ranges from a low of about $12.4 million to a high of $34.3 million. These PCV values represent potential refunds to customers that were ultimately not refunded due to application of the PCAM deadband, sharing and earnings tests. The total potential refund to customers over this time period is about $112 million out of which $5.5 million was actually refunded after application of the various sharing mechanisms.[32]

PGE claims that SB 838 requires dollar-for-dollar recovery of its net power costs related to wind in addition to the capital costs that are currently accounted for in the RAC. CUB fundamentally disagrees with PGE on this point. But this disagreement is

[32]UE 286 Staff/100/Crider/14.

irrelevant if PGE is actually recovering more than its total net variable power costs since these include costs associated with wind forecasting error and wind integration. In other words, there is no reason to fix a problem that does not exist.

IV. Energy Efficiency and Marginal Cost of Service

As we talk about energy efficiency ("EE") and customer classes, it is important to recognize that there are two ways in which EE interacts with customer classes: first, ETO Programs offer incentives to customer classes to achieve savings; second, customer classes fund ETO EE programs through surcharges on utility bills. These surcharges vary by customer class. In the testimony that follows, CUB will discuss both the programs targeting customer classes and the funding charged to customer classes.

A. EE Is An Energy Resource Which Should Be Included In Any Marginal Cost Study

Energy efficiency[33] is an energy resource that has been and is being consistently deployed throughout Oregon, specifically in PGE's service territory. Not only is EE an energy resource, at 2.4 cents per kWh, [34] it is the most cost effective resource. This implies, from a least cost/least risk planning point of view, that on the margin, all energy needs should be first met by EE. In fact, for Oregon residential customers, EE has been the primary resource added to meet load growth.

Therefore, as the go-to energy resource, EE must be included in the modeling of energy marginal costs. A model of energy marginal costs that excludes EE would be

[33] CUB uses ETO EE as a minimum EE benchmark, although it recognizes that EE is deployed by other parties and independent of the ETO.
[34] http://energytrust.org/library/reports/2013_ETO_Annual_Report.pdf at pg 26.

both inaccurate and misleading. Fortunately, EE is a tractable, cumulative resource that is well documented by both PGE and the ETO.

The following table demonstrates the recent acquisition of EE in Oregon through programs that target specific customer classes (later on CUB will discuss EE in terms of the customer class that funded the resource).

Table 1: ETO EE Programs Targeting Customer Classes[35]

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

EE is a cumulative resource. The 316 mWa of EE will, therefore, accumulate and continue to grow and serve Oregon customers year after year. By way of example, once a home is weatherized, its load reduction remains permanently off of the servicing utility’s system for as long as the home is standing. This means that resources which would otherwise have been used in the annual production of the former (pre-weatherization) energy load will continue to be spared. To give an idea of the scope of the EE investment impact, consider that the total amount of all electric EE deployed by the ETO since 2008, serves more energy needs than all of PGE's hydro resources

[35] CUB Exhibit 103 tab ETO tables.

combined.[36] All ETO EE specifically acquired from PGE customers, from 2008 to date, nearly matches all of the PGE wind resource to date.[37]

Table 2: EE Acquired From PGE Customers (2008-2013)[38]

PGE specific		
year	amw	units
2008	18.58	mWa
2009	20.4	mWa
2010	25.6	mWa
2011	28.18	mWa
2012	32.23	mWa
2013	35.62	mWa
total	160.61	mWa

The impact is even more significant if one includes all EE investment back to 2002, since the Energy Trust began:[39]

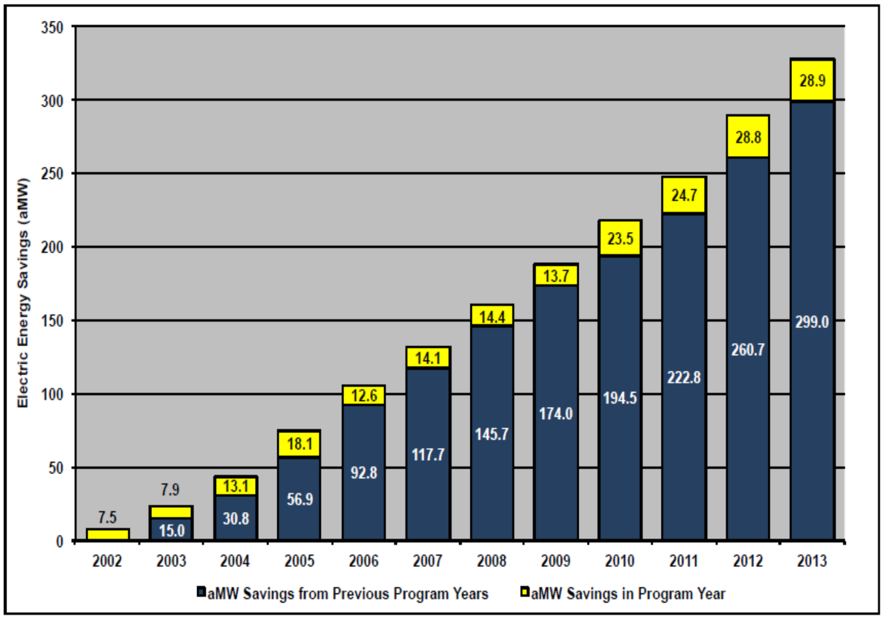
[36] http://files.shareholder.com/downloads/POR/3215315514x0x738218/180e3b26-c79e-4c3b-998b-77ed43731cf7/Final_2013_Annual_Report.pdf at page 15, which estimates max hydro energy supplied at 250 mWa

[37] http://files.shareholder.com/downloads/POR/3215315514x0x738218/180e3b26-c79e-4c3b-998b-77ed43731cf7/Final_2013_Annual_Report.pdf at page 15, which estimates max hydro energy supplied at 250 mWa

[38] CUB Exhibit 103 tab ETO tables.

[39] CUB Exhibit 103 tab ETO Brief.

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.

i. EE Is Included In IRP As A Resource

According to PGE's IRP, the top performing portfolios of resource options to meet future demand are all made up of EE, baseload natural gas, RPS-eligible renewables and natural gas peaking units:

> The top three portfolios perform similarly and each could be considered a viable candidate for a preferred portfolio. Each of these three candidate portfolios follow the above described model of combining EE, base load natural gas plants, new renewables to meet RPS requirements, and natural gas peaking units to provide capacity.[40]

PGE is planning to use EE combined with natural gas plants and renewables to meet load growth and natural gas peaking units to provide capacity. The marginal cost study should, therefore, reflect these actual marginal resources.

[40] PGE 2013 IRP, Executive Summary, page 207.

ii. The Governor's Energy Plan Proposes That All Load Growth Comes From EE

The Governor of Oregon has developed a 10-year energy plan for the State which emphasizes the use of EE:

> **The 10-Year Energy Action Plan focuses on three core strategies:**
>
> **1. Maximize energy efficiency and conservation to meet 100 percent of new electricity load growth.**
>
> Oregon ranks fourth in the nation in energy efficiency. Since 1980, Oregon households and businesses have realized energy efficiency and conservation savings equivalent to eight to ten power plants. The result has been lower energy bills, a cleaner environment, and a thriving local energy service industry that exports its technology and expertise to the world. To build on this success, to capture deeper, harder-to-reach efficiency and conservation opportunities, and to scale them community-wide, will require new data, new financing tools, rate design changes and trained workers. The Northwest Power and Planning Council's 6th Power Plan states that the region can meet 85 percent of new load growth through energy efficiency and conservation. This plan calls for Oregon to meet all new electric load growth through energy efficiency and conservation. We will start at home. Every occupied state-owned building will establish baseline energy use, undergo an energy audit and identify cost-effective retrofits in the next ten years, improving the performance of up to four million square feet of identified office space and using the state as a market driver for greater energy efficiency and conservation projects.[41]

Whether the expectations is 85% of regional load growth being served by EE as the Governor quotes from the NPPC or 100% as the Governor calls for within Oregon, there is little doubt that Oregon plans to rely on EE for the majority of its load growth. EE truly is the marginal resource.

iii. The Last 15 Years Of Data Show That EE Has Been The Marginal Cost

The following table compares PGE's projected residential test year load to actual load in 2000. It shows that the number of customers has increased by 16%, while the average monthly usage has decreased by 14%. The result is that while the number of

[41] Cover letter from Governor John Kitzhaber, page 1, attached to 10-Year Energy Action Plan, December 14, 2012.

customers has increased by 16%, the amount of resources needed to serve that new increased level of customer load has increased by less than 1%.

Table 3: PGE is Meeting Residential Load Growth With EE

year	residential customers	average load (kWh/month)	total residential load (MWh)
2000[42]	637,331	11,663	7,433,191
2015[43]	740,049	10,084	7,462,740
% change	16%	-14%	0.40%

B. EE Is Different Than Other Resources Because Customer Classes Buy It In Different Increments.

Current EE funding has been established legislatively, with all customers funding EE through the public purpose charge contained in SB 1149 and some customers funding additional EE from authority granted the Commission in SB 838.

i. SB 1149

In 1999, the Oregon Legislature passed SB 1149 which established a public purpose charge of 3% and directed that 63% of the 3% public purpose charge go to new cost-effective conservation and new market transformation programs:

> Beginning on the date an electric company offers direct access to its retail electricity consumers, except residential electricity consumers, the electric company shall collect a public purpose charge from all of the retail electricity consumers located within its service area for a period of 10 years. Except as provided in paragraph (b) of this subsection, the public purpose charge shall be equal to three percent of the total revenues collected by the electric company or electricity service supplier from its retail electricity consumers for electricity services, distribution, ancillary

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[42] Oregon Utility Statics Guidebook, OPUC, http://www.puc.state.or.us/docs/statbook2006.pdf.

[43] UE 283 PGE/1402/Cody/4.

> services, metering and billing, transition charges and other types of costs included in electric rates on the effective date of this 1999 Act… .
>
> (3)(a) The Public Utility Commission shall establish rules implementing the provisions of this section relating to electric companies.
>
> (b) Subject to paragraph (e) of this subsection, funds collected by an electric company through public purpose charges shall be allocated as follows:
>
> (A) Sixty-three percent for new cost-effective conservation and new market transformation;[44]

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." 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 plant. The result of this is that customer classes with less energy demand and higher distribution usage will pay more for demand-side investments (energy efficiency) then those same customers would pay for a supply-side investment (Port Westward 2 or Tucannon). The customers who use less energy but more distribution are the customers with smaller individual loads, residential and small commercial.

ii. SB 838

The Renewable Energy Act, SB 838, allows for the collection of additional funds for investment in cost-effective EE, but only from customers whose usage falls below 1aMW:

[44] SB 1149, Section 3: http://energytrust.org/About/PDF/sb1149.pdf.

> SECTION 46. (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
>
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>
> (a) Is not required to pay an amount that is more than three percent of the consumer′s total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>
> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section. [45]

The current interpretation of that law is to maintain industrial programs at the same percentage of funding as they were before SB 1149. An ETO Briefing Paper states as follows:

> 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

[45] SB 838, 2007 Legislature; ORS 757.689(2)(b).

or sooner. This funding limitation means that Energy Trust may not be able to secure all cost-effective efficiency from these customers. [46]

While EE funded as part of SB 1149 was more heavily weighted towards residential and small commercial customers than generation costs, EE funded by SB 838 is even more one-sided in its funding. SB 838 funding comes only from customers who are below 1aMW. While this law prohibits large customers from receiving any direct benefit[47] from the additional funding contained within the law, as CUB will show below, the current interpretation of the law nonetheless allows large customers to receive a huge direct benefit in the form of lower rates due to less expensive resources, which is the primary benefit to investing in EE.

iii. Residential Customers Buy Half Of All Efficiency: Without Reflection Of This Fact In The Marginal Cost Of Service Study, Residential Customers Are Effectively Buying System Resources.

The Company reports that residential customers (Schedule 7) funded more than half of all energy efficiency in 2013[48] but residential customers are less than 40% of system load.[49] However, the ETO reports an ever declining portion of energy efficient programs targeted at residential ratepayers. ETO projects 2014 to be an all time low for the proportion of EE programs aimed at acquiring EE from residential ratepayers, while at the same time residential customers are funding more EE than all the other groups combined.

[46] Briefing Paper: Energy Trust of Oregon Energy Efficiency Programs, June 7, 2013, p 25-26
[47] SB 838 Section 46 (2)(b); ORS 757.689(2)(b).
[48] CUB Exhibit 104.
[49] UE 283 PGE/1402/Cody/ 4.

Table 4: EE Programs Targeting Customer Classes[50]

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

Notice how EE programs targeting Commercial customers have gone from a low of 28.92% in 2008, to the lion's share in 2014 at 41%. Industrial EE programs have followed a similar pattern. On the other hand, residential customers, the class that funds over half of all ETO EE, have seen a decline in programs targeting the residential class. Today, residential programs make up ¼ of ETO EE acquisition, down from almost half of acquired EE the year after SB 838 was passed. The reason for this change is that the class of customers which receives the bulk of the EE programs is not the same class from which those funds are collected.

The Energy Trust has stated:

> The mix of electric energy savings across programs was approximately the same as in previous years. In 2013, commercial and industrial energy efficiency programs account for 72.4 percent of total electric energy savings (compared to 70.4 percent in 2012). Residential energy efficiency programs account for 27.6 percent of total electric energy savings in 2013 (compared to 29.6 percent in 2012)[51]

The economic rationale behind this decision is reasonable: EE is a resource. The ETO approaches acquiring EE from a least cost perspective and allocates program funding where it will have the most bang for its buck, where the most energy

[50] Exhibit 103 tab ETO tables.
[51] http://energytrust.org/library/reports/2013__Economic_Impacts_Report.pdf, pg 2.

reduction can be earned with each dollar spent, regardless of the source of those funding dollars. The ETO takes aim at least cost acquisition of a resource called conservation, which leads to lower system costs.

Therefore, in alignment with the ETO mission, to meet EE goals in the most cost effective manner possible, it may make sense to offer more commercial and industrial programs than residential programs. The problem, however, is that under the current structure such funding is not possible.

Although CUB understands the economic rationale of the ETO approach, both CUB and the ETO recognize that the current system is, in fact, broken. Within the next 12-24 months, the ETO predicts that there will still be EE programs, available, in theory, to industrial customers, but in reality, they will be unattainable. In essence, the ETO will finally bump up against the industrial "direct benefit" cap and there will be EE left on the table, EE that Oregon is touted nationally for striving to achieve. However, the EE that is forecast in the IRP is based on the potential EE and is not adjusted for the artificial cap placed on industrial programs by the current interpretation of the law. Because this cheap resource will not be available to the extent planned for in the IRP, PGE will be forced to find more expensive resources to meet the additional load that could have been avoided with more up-take of the industrial EE programs. Most important of all, all PGE ratepayers will pay higher costs because of this failure to gain all cost-effective EE.

iv. By Reflecting EE In The Marginal Cost Of Service Study, All Customers Get What They Are Funding.

Including EE as a marginal resource, and allowing customers to get credit for the EE that they are funding will, (1) improve accuracy (2) provide the proper economic 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.

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[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.

[59] CUB Exhibit 103 tab model.

Table 8: Marginal Energy Costs[60]

Schedules	CUB Marginal Energy Costs	PGE 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.

C. PGE Has Known Of The EE CAP Problem, But Has Not Made Any Proposal To Solve It

It is not just CUB and the ETO who recognize that the limitation of large customer EE may lead to not acquiring all cost effective EE. PGE itself has also recognized this:

> PGE does foresee potential barriers within the next five years to achieving all cost-effective energy efficiency (EE) in the IRP. To highlight one such barrier and as discussed in PGE's Response to CUB Data Request No. 026, large-user funding limitations could become a barrier to achieving all cost-effective EE savings in that business sector. Project interest for this customer group has been much higher in the past three years than the years against which the funding cap is measured. We expect this trend of interest to remain steady or increase, largely in the semiconductor industry, hospitals, and colleges and universities with a range of cost-effective projects.[63]

In fact, PGE has been aware of this problem since 2012, but has done little to try to remove the barriers to achieving all cost-effective EE that is in its IRP.[64] CUB asked PGE what actions it had taken each year since the Company was made aware of the problem and the answer really came down to "not much."

Actions Taken By PGE To Address Industrial EE Barrier[65]

> **2012:** PGE learned of the issue from Energy Trust and observed the Energy Trust Board Retreat in June 2012 where the issue was raised. The issue was discussed internally by PGE management. No actions were specifically taken to address the barrier to large-user funding in 2012, since PGE had just become aware of the possible limitation.
>
> **2013:** PGE observed Energy Trust's Board Retreat in June 2013, where the cap was discussed in detail, and PGE's management was alerted to the issue and reviewed the Energy Trust's Board Packet materials on the subject.
>
> **2014:** PGE has been working closely with Energy Trust to compare compliance analyses and is in agreement that we are approaching the funding cap. In addition,

[63] CUB Exhibit 105.
[64] CUB Exhibit 106.
[65] CUB Exhibit 106.

> PGE attended a multi-stakeholder meeting January 31, 2014 on the topic and will continue to support Energy Trust in any data related matters and provide feedback on any program design changes needed if the cap is reached.

D. Implementing CUB's Proposed Marginal Cost Study In This Case Will Remove The Improper Benefit Industrial Customers Are Receiving.

CUB believes that it is the policy of this Commission that utilities fund all cost effective EE. Unfortunately, that is coming to an end. According to ETO estimates, based on the current interpretation of the direct benefit provision of SB 838, these benefits will end in 2015.[66] CUB believes that the current interpretation of direct benefit clause is incorrect. The direct benefit of any EE investment is the benefit of a system that functions at a lower cost and functions more efficiently. Customers benefit from EE because it lowers the costs of the utility and puts downward pressure on rates. Large customers benefit for the same reason as all customers. And large customers are benefiting from SB 838 dollars because those dollars are directly leading to lower costs to PGE to meet its load. The only way to prevent large customers from receiving this direct benefit is to ensure that the direct benefit flows to the classes of customers who funded the purchase of that EE.

E. Implementing CUB's Proposed Marginal Cost Study Will Allow Residential And Small Business Customers To Purchase All The Cheap EE Available From Industrial Customers Because Residential And Small Business Customers Will Get Credit For That Purchase.

CUB's marginal cost approach does not propose to re-legislate or remove the cap. The law still clearly states that large customers should not receive any direct benefit from

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[66] SB 838 Section 46; ORS 757.689(2)(b).

the additional funding provided by SB 838.[67] CUB's proposal is consistent with that principle. CUB's marginal cost approach directs the benefits of conservation funding to the purchaser of the conservation, not to the vendor selling the product. This accounting removes this subsidy from the system. Residential customers can continue to fund the majority of EE, essentially buying system resources for customers of PGE at 2.7 cents/kwh; the ETO can continue to direct large shares of those programmatic dollars to large customers; and PGE can give credit to those who pay for EE programs – for example, the residential ratepayers and small commercial customers of PGE. Since the direct benefit, which is lower system costs, will go to those who funded the EE, then those customers will not need to purchase such a large share of the next-best resources, which are invariably more expensive. In this way, the direct benefit will always go to the funders of the EE programs, and the direct benefit cap will remain untouched.

F. The Alternative: Removing the Cap on Industrial Funding of EE

Much of this problem is caused because SB 838 allowed additional funding for EE, but put a cap on the amount of funding that a utility could receive from customers with loads of more than 1aMW. An alternative to CUB's approach would be to amend the law and remove this artificial cap. This would allow all classes of customers the ability to fund EE least cost/least risk resources.

When revisions to SB 838 were being negotiated before this year's legislative session, CUB suggested that this is an area where SB 838 should be fixed. CUB found little support from utilities or from industrial customers for such a change. Removing the cap would still leave in place a system where small customers fund EE at a greater rate

[67] ORS 757.689(2)(b).

than supply-side resources because EE is being purchased as a charge to all revenues including distribution, rather than an energy charge.

Without the ability to remove the cap on funding of EE, CUB believes the best mechanism is to give funders of EE credit for that which they are funding.

VI. Conclusion

In this testimony, CUB is making the following recommendations:

January 1, 2015 Rate Change. Rates should not increase on January 1, 2015, because the record in this case does not support that PGE will be earning outside of its reasonable range on that date.

Port Westward 2. CUB is concerned that Post Westward 2 is not being used to integrate intermittent resources which are a large part of its justification. If the plant is not going to be used for integration of intermittent resources, then the Commission should disallow a portion of its capital costs to reflect the difference between the flexible resource that was described in the RFP and the peaking resource that PGE actually built.

Tucannon. CUB recognizes that the capacity factor is an important element in the prudency of a wind facility. CUB believes Tucannon is prudent with the capacity factor that PGE forecast in its most recent study. However, PGE has proposed that the capacity factor be updated later after the record in this docket is closed. If PGE's approach is approved, CUB believes a prudence review must be delayed until the capacity factor study is completed.

PCAM Carve Out For Renewables. CUB was a party to the negotiations of the Renewable Portfolio Standard. The law was not intended to require dollar-for-dollar recovery of costs associated with renewables. CUB believes PGE has failed to make a case for carving these costs out from the PCAM and urges the Commission to reject PGE's proposal.

Marginal Cost Study. CUB recommends that the Company modify its marginal cost approach to more accurately reflect the marginal resources employed in serving customers. In particular, CUB recommends that consistent with the IRP, the Company's acquisition of EE, via the ETO, be recognized as a marginal resource. Moreover, in an attempt to align the real impact of each customer class on the system CUB recommends that the Company reconcile conservation purchased by each schedule, appropriately giving customers credit for marginal resources purchased. CUB proposes a methodology for implementing this approach.

Industrial Efficiency. ETO projects that it will no longer be able to acquire all cost effective energy efficiency that is in PGE's IRP because of the current interpretation of the cap on industrial programs. CUB believes that the direct benefit cap should be placed, not on incentives associated with programs, but on the direct benefits of EE - the lower costs it brings to the system. By interpreting the cap in this manner, and allocating the benefits of EE to the funders of EE through the marginal cost study, the barrier on acquiring additional industrial EE will be removed.

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, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UE 233, UE 246, 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

WITNESS QUALIFICATION STATEMENT

NAME:	Jaime McGovern
EMPLOYER:	Citizens' Utility Board of Oregon
TITLE:	Senior Utility Analyst
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	PhD, Economics W.P. Carey School of Business Arizona State University Masters of Science, Economics Arizona State University Bachelors of Arts, Economics and Mathematics Arizona State University
EXPERIENCE:	Provided testimony or comments in a number of OPUC dockets, including UE 262, UM 1633, and UM 1654. Worked as Utility Analyst at the Oregon Public Utility Commission from 2006-2008, providing advice on rate cases, analysis in meetings with the Bonneville Power Administration and performing benchmarking studies regarding telecom and electric competition in the state of Oregon. Economics professor at Mesa Community College and the State University of New York from 2004–2010.

CUB EXHIBIT 102 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 14-043

May 6, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 037
Dated April 23, 2014

Request:

Does the Company have predictions for the SB 1149 and SB 838 funds in 2015. If so, please provide them (a) SB 1149 funds broken down by customer class and (b) SB 838 funds broken down by customer class.

Response:

Attachment 037-A contains 2015 projections of both SB 1149 (Schedule 108) and SB 838 (Schedule 109) collections by rate schedule. For the SB 1149 projections, PGE presumed a January 1, 2015 on-line date for both Port Westward 2 and Tucannon River.

UE 283

Attachment 037-A

Provided in Electronic Format only

2015 Projections of SB 1149 & SB 838 Collections

Rate Schedule	2015 SB 838 Amount
Schedule 7	$27,612,139
Schedule 15/515	$95,841
Schedule 32/532	$5,322,807
Schedule 38/538	$173,156
Schedule 47	$81,577
Schedule 49/549	$219,375
Schedule 83/583	$7,608,994
Schedule 85/485/585	$7,249,370
Schedule 89/489/589	$0
Schedule 90/490/590	$0
Schedule 91/95/591/595	$527,220
Schedule 92/592	$8,517
Total	$48,898,997

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
	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three	Fixed		Cost
Grouping	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Phase	Costs	Subtotal	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.

*COPIED FROM UE283 PGE RATESPREADGRC15.XLSX NON-CONFIDENTIAL 1400 WORKPAPERS

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				
aMW	commercial	industrial	residential	total	units	ETO annual report
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

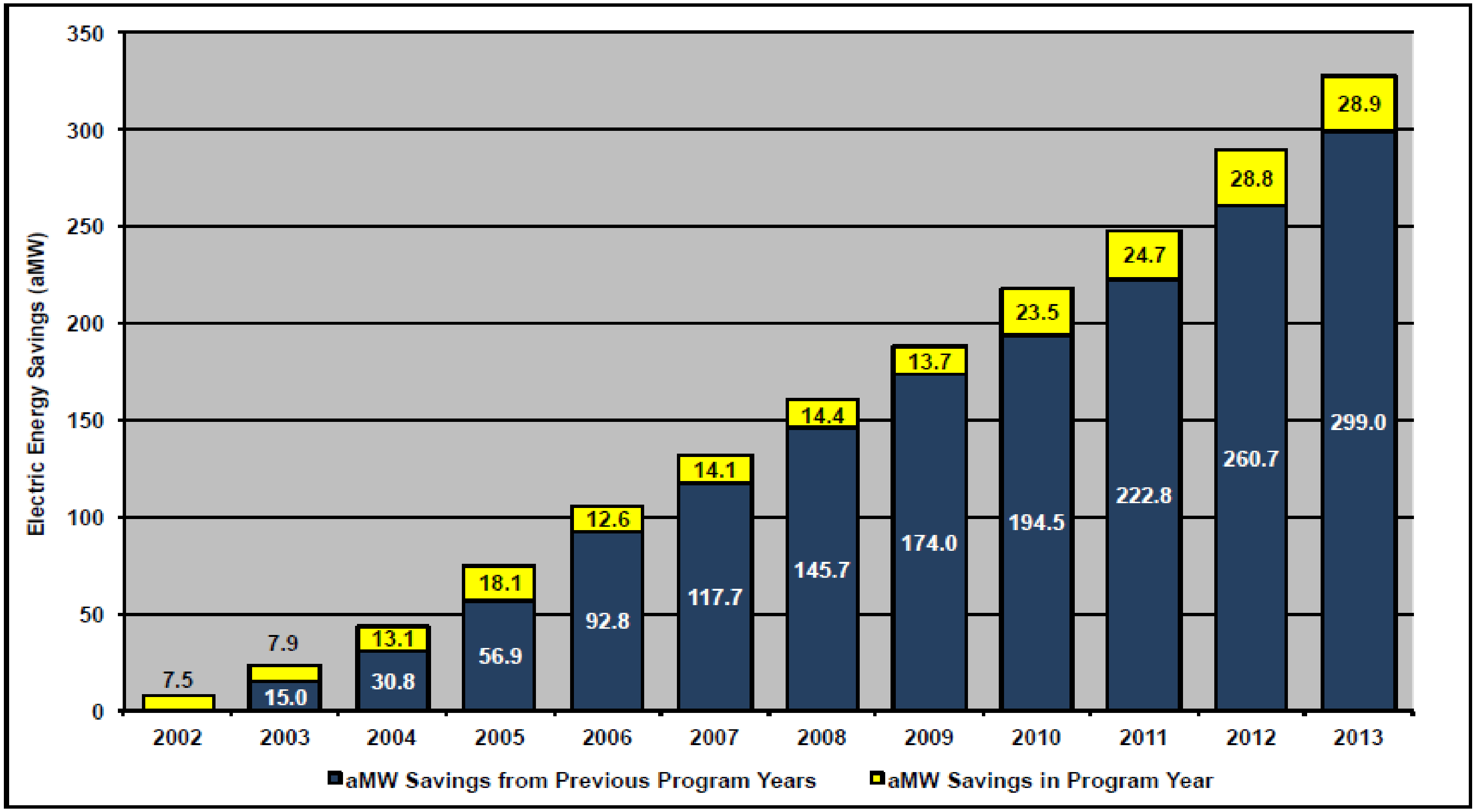
Schedules	CUB Marginal Energy Costs	PGE Marginal Energy Costs		Generation Capacity Allocation	Marginal Capacity Costs ($00	Capacity & Energy Costs ($000)	& Energy Allocation Percent	Capacity & Energy Costs ($000)	Marginal Cycle Basis Costs ($000)	Capacity Capacity & Energy Costs ($000)	CUB proposal Allocated		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			
r	3990			
theoretical total resource r	865			
theoretical renewable nee	800			
total EE needs	309	79.95%	pge energy revenue re	$975,598,466
total procurement	2016			
theoretical traditional reso				
	3190			
Total Resource Needs Ne				

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

		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**

March 20, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 027
Dated March 6, 2014

Request:

Does PGE see any barriers over the next 5 years to achieving all cost effective energy efficiency contained in the IRP?

Response:

Yes, PGE does foresee potential barriers within the next five years to achieving all cost-effective energy efficiency (EE) in the IRP. To highlight one such barrier and as discussed in PGE's Response to CUB Data Request No. 026, large-user funding limitations could become a barrier to achieving all cost-effective EE savings in that business sector. Project interest for this customer group has been much higher in the past three years than the years against which the funding cap is measured. We expect this trend of interest to remain steady or increase, largely in the semiconductor industry, hospitals, and colleges and universities with a range of cost-effective projects.

March 20, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 028
Dated March 6, 2014

Request:

To the degree PGE sees a barrier to achieving cost effect energy efficiency in the test year or in the next five years:

a. **Please describe that barrier.**
b. **When did PGE first become aware of that barrier.**
c. **Please describe in detail all actions PGE has undertaken in 2014 to address this barrier.**
d. **Please describe in detail all actions that PGE took in 2013 to address this barrier.**
e. **Please describe in detail all actions that PGE took in 2012 to address this barrier.**

Response:

a. PGE's Response to CUB Data Request No. 026 provides a description of the most likely barriers.

b. The Energy Trust of Oregon (Energy Trust) saw indications that PGE's large energy users were nearing their funding cap in 2012 and began to raise awareness by sharing funding compliance studies with PGE. Energy Trust described how growing interest in programs from large users was nearing the cap, although not yet reaching the cap or making program design adjustments.

c. PGE has been working closely with Energy Trust to compare compliance analyses and is in agreement that we are approaching the funding cap. In addition, PGE attended a multi-stakeholder meeting January 31, 2014 on the topic and will continue to support Energy Trust in any data related matters and provide feedback on any program design changes needed if the cap is reached.

d. PGE observed Energy Trust's Board Retreat in June 2013, where the cap was discussed in detail, and PGE's management was alerted to the issue and reviewed the Energy Trust's Board Packet materials on the subject.

   In 2013, a separate barrier to reaching all cost-effective efficiency was addressed by PGE and Energy Trust. Energy Trust's 2014 budget exceeded the 2014 IRP savings estimate due largely to a newly realized opportunity in the market. Instead of completely eliminating opportunities for consumers to purchase any lamps less efficient than CFLs, the new lighting standards allowed for some less-efficient-but-compliant halogen bulbs to remain in the market. To quickly implement a program to direct customers away from the less-efficient bulbs, Energy Trust's products program recommended funding a quick initiative that would increase savings by 1aMW but require additional funds. PGE reviewed the opportunity and decided provide Energy Trust with additional funding (drawing from reserve funding for 2014) to acquire that savings.

e. PGE learned of the issue from Energy Trust and observed the Energy Trust Board Retreat in June 2012 where the issue was raised. The issue was discussed internally by PGE management. No actions were specifically taken to address the barrier to large-user funding in 2012, since PGE had just become aware of the possible limitation.

UE 283 – CERTIFICATE OF SERVICE

I hereby certify that, on this 11th day of June, 2014, I served the foregoing **OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket UE 283 upon each party listed in the UE 283 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending one original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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