BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
PORTLAND GENERAL ELECTRIC,	)
Request for a general rate revision.	)

SURREBUTTAL TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

September 15, 2008

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of PORTLAND GENERAL ELECTRIC, Request for a general rate revision.	SURREBUTTAL TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction.

In February, PGE filed its case for a 9.5% rate increase for residential customers. Opening Testimony from Staff and other parties who reviewed the filing demonstrated a lack of support for the Company's rate hike.

In its Opening Testimony, Staff stated that it had trouble understanding PGE's need for a non-power cost increase:

> Staff found it very difficult to support the basis of PGE's request for an increase for the general non-power cost portion of the rate proceeding. While the rate request presented by the Company in its application for UE 197 purported to identify new programs and other changes as justification for its rate request, Staff's review did not verify those assertions.

UE 197/Staff/100/5.

In our Opening Testimony, CUB argued that the rate filing, and the answers to our data requests, showed a Company that had made little effort to control its costs.

Since that time, CUB has met with PGE's senior management and its Board of Directors. In those meetings we described our testimony, but offered an alternative explanation. While the evidence did not demonstrate a Company that is trying to control costs, we suggested that it could be that the Company was working to control costs, but had failed to tell that story.

Unfortunately, PGE's Rebuttal again fails to the story of a company working to control costs. It offers no real evidence that the Company has tried to control its costs, has a Company culture dedicated to cost control, or has strong cost reviews processes. Rather than reviewing its costs to identify additional places to control costs, or to demonstrate actions that it had already taken to control 2009 costs, the Company simply asserted that there was more savings, and pointed to AMI savings in 2010. At the same time, the Company has now identified additional costs they wish to add into rates and changes to cost allocation, which combine to increase the rate hike to 13.9% for residential customers.[1] This means that residential customers now face an increase that is 50% higher than what the Company proposed in February.

Based on the Company's Rebuttal Testimony, we must conclude that PGE **has** accurately told its story on cost control, and that the resulting evidence proves that PGE has not made much effort to control its costs. This lack of cost control is a large driver of this rate case.

This is disappointing. We had hoped that in response to the criticism leveled by CUB and the Staff, and increasing power costs, that the Company would make an effort

[1] UE 197/PGE/2003/1.

to identify additional places to save money. But, by the Company's own evidence, it has made no such effort.

II. PGE Shows Little Effort to Control Costs and Offers No New Cost Reductions.

In our Opening Testimony, we demonstrated that there was little evidence that PGE has carefully controlled its costs. In its Rebuttal Testimony, PGE objects to our conclusions, but rhetoric aside, offers no new reductions beyond the partial settlements and accepting some recommendations from the PUC staff.

A. In spite of partial settlements, and accepting limited staff adjustments, PGE is asking for a larger rate hike.

In its Rebuttal Testimony, the Company cites that it had reached two settlements with other parties that together reduce costs by $18.6 million,[2] one on power costs that reduces power costs by $5.1 million, and one on non-power costs that reduces costs by $13.6 million. However, nearly two-thirds of this, $12.9 million, is a reduction from PGE's requested increase in its ROE. Since ROE was established early last year, CUB believes that PGE has had little or no chance to gain a higher ROE.[3] Not counting this change in ROE, the company has agreed in settlement to less than $6 million in reductions to its requested increase of $183 million. The partial stipulations have had little impact on the overall rate effect and settled few of the significant issues in this case.

[2] UE 197/PGE/1300/5.
[3] UE 197/CUB/100/41.

PGE then goes on to explain that after reviewing other parties' testimony, it was agreeing to accept a reduction to its case of $16.2 million.[4] This reduction comes entirely from PGE accepting some of the reductions advocated by the PUC staff. PGE does not accept any reductions that were advocated by CUB or ICNU, nor has it identified any reductions on its own.

In addition to these decreases, PGE has also added a number of additional costs since its original filing[5]:

*On April 3rd, PGE added an additional $1.3 million which reflects additional staffing positions, and other "corrections."

* PGE updated its load forecast and increased revenue requirement by $10 million.

*PGE updated its power costs by $21 million in April.

*PGE updated its power costs by an additional $92 million in July.

Overall, in spite of the reductions PGE has agreed to, it has increased its requested rate increase by nearly $40 million since filing this case. The increase to residential customers has gone from 9.5% to 13.9%.[6]

B. PGE claims that it can reduce costs in tough times, but has yet to do so.

Since PGE filed this case in February, the economy, both nationally and in Oregon has suffered. Unemployment has gone up. Employment in Oregon peaked in February, the same month that PGE filed its case. Since then, Oregon has lost more than

---

[4] UE 197/PGE/1300/5.
[5] UE 197/PGE/1300/8-9.
[6] UE 197/PGE/2003/1.

11,000 jobs and unemployment has reached 6%.[7] In addition, consumers have been hit hard with higher costs for gasoline and groceries.

In the Company's Rebuttal Testimony, the Company acknowledges that the economy is experiencing tough times and that the Company should evaluate whether it can adjust any costs and "defer some costs:"

> We fully appreciate that the current state of the economy and rising costs are major concerns for our customers. Like any business, we understand that in tough times we must evaluate whether a given expenditure needs to be made now, or if a greater benefit can be achieved by deferring costs to a later time… Some costs can and should be deferred in a tough economy.

UE 197/PGE/1300/

> Even as this rate case proceeds, PGE is constantly looking for efficiencies, more effective strategies to control costs, and opportunities to leverage market forces to our customers' advantage.

UE 197/PGE 1300/4.

However, in its Rebuttal Testimony, PGE fails to identify and quantify a single dollar of savings in the 2009 test year outside of what the Staff identified for them. For our Opening Testimony, we examined PGE's 2009 test year budget, asked a series of data requests, and concluded that the Company had done little to control costs. The Company responded in its Rebuttal Testimony, defending what it has done to control costs, and even claiming that it is continuing to focus on cost control as this case proceeds. But all of this continuing focus has not led the Company to identify and list any costs that can be reduced, with the exception of agreeing to a handful of PUC staff adjustments that reduce the 2009 test year revenue requirement. Having the Company recognize that times are tough and that the Company should examine its costs in light of

[7] CUB Exhibit 201.

the economy would be admirable if the Company actually made an effort to examine its costs. But according to the evidence in this rate case, it hasn't.

C. PGE's new budget *might* find savings.

CUB Exhibit 202 is the response to a data request wherein we asked the Company if it had identified any additional cost savings that were not included in the Staff filing. In its response, PGE stated that it was in the process of developing its 2009 budget, "which may identify additional costs or savings compared to the 2009 test year forecast."

PGE filed its case in February. Since that time, the economy of Oregon has declined and customers have fallen on increasingly hard times. PGE acknowledges this and admits that in light of the faltering economy, it should look at its costs to see if some can be deferred. Again, the Company has yet to do so. Maybe when it puts together its budget for next year, it will look for some additional savings. But that budget will be finalized after Staff and intervenors have finished putting our case on the record, so the only way these savings can be passed through to customers is through a voluntary effort by PGE. However, PGE would have no obligation to disclose these savings in this case. Instead, the Company would be allowed to retain these savings as additional corporate earnings.

While PGE has not identified any cost reductions before finalizing its budget, it has not been so conservative with identifying cost increases, which is why the rate impact coming from this case has increased since its original filing.

D. PGE claims that it is controlling its costs, but offers no evidence.

In our Opening Testimony, CUB pointed out that PGE could only identify less than $1 million in savings from a revenue requirement of $1.8 billion. PGE objects to this observation:

> CUB's assertion, that PGE could only identify a small list of cost saving measures in its initial rate case filing, assumes that the examples give were the only measures taken. That is simply not the case and distorts the Company's operations.

UE197/PGE/1300/17.

PGE goes on to cite cost savings from UE 180 that occurred between 2002 and 2005 and then asks itself if there are more cost savings available:

> Q. Still, aren't more cost savings available?
>
> A. Yes, and CUB ignored the largest component of cost savings identified in testimony (PGE Exhibit 100, page 13), which is the operational savings from the advanced metering infrastructure (AMI) project – a large project that will engage significant resources of numerous PGE departments over several years. PGE has estimated that the annual operational savings from AMI will be approximately $18.2 million after full deployment is completed in 2010…

UE 197/PGE/1300/18-19.

PGE says that CUB is wrong in concluding that the Company could only identify less than $1 million in cost savings related to the 2009 budget. According to PGE, our mistake was in taking some examples they listed and assuming that that was the complete list. PGE then cites cost savings that occurred before their last general rate case and to operational savings from AMI that will likely occur sometime after the next general rate case. But PGE fails to add any specific, quantifiable savings related to this rate case.

CUB followed up with a data request asking PGE to back up their cost savings claim with facts:

> Request:
>
> Mr. Piro (PGE/1300/17) states that "CUB's assertion, that PGE could only identify a small list of cost savings measures in its initial rate case filing, assumes that the examples given were the only measures taken. That simply is not the case and seriously distorts the Company's operations." Please identify all other cost savings that impact the test year.
>
> Response**:**
>
> PGE has identified savings in the following dockets:
>
> UE 180, PGE Exhibit 500, pages 3-4.
>
> UE 197, PGE Exhibit 100, pages 11-15.
>
> UE 197, PGE Exhibit 1300, pages 14-15.
>
> PGE has not performed additional analyses to identify every savings or avoided cost associated with each capital job or O&M project that PGE has undertaken in the recent past that could have impacted the test year in one form or another. One reason is that, as noted in PGE Exhibit 1300, page 21, many projects or costs are necessary by regulatory or service requirements, or have minimum discretionary components. Another reason is that numerous projects do not have easily quantifiable benefits. In addition some projects provide needed capabilities that existing systems do not. Again, the benefits may be difficult to quantify, but are fully valid.

CUB Exhibit 203.

PGE accuses CUB of distortion, and claims that the list we referred to in the Company's Opening Testimony is a list of examples. But when asked what other costs savings there are, they point again back to that list, to the pages of Rebuttal Testimony that refer to UE 180 and AMI. PGE provides no new evidence to support its argument that there are additional cost savings that impact the 2009 budget.

It is time for PGE to stop this. PGE has the burden of proof in this case. PGE has failed to identify additional cost savings in its 2009 budget. Saying CUB is wrong is fine; but the Company cannot, or will not, back up that claim by identifying and quantifying the costs savings that are in addition to these examples.

Therefore, on this issue, CUB's Opening Testimony stands, unrebutted.

E. PGE wants AMI to be an issue in this case and then it doesn't.

In its Opening and Rebuttal Testimony, PGE goes out of its way to cite AMI as the primary example of how it is saving money. CUB did not address AMI in our Opening Testimony, because it is unrelated to the 2009 test year that we are examining here. PGE criticized CUB for ignoring AMI:

> CUB ignored the largest component of cost savings identified in testimony (PGE Exhibit 100, page 13), which is the operational savings from the advanced metering infrastructure (AMI) project.

UE 197/PGE/1300/18-19.

If PGE thinks it is necessary for CUB to address AMI, we are willing to do so. We followed up their Rebuttal Testimony with some data requests on AMI. PGE responded by arguing that AMI is not relevant.

> PGE objects to this request as seeking information that is neither relevant nor likely to lead to the discovery of admissible information. AMI costs are not part of this rate case.

CUB Exhibit 203.

The Company criticizes CUB for ignoring AMI, and when we ask data requests to examine their assumptions about AMI, they tell us it is not "relevant." But if "it is the largest component of cost savings" that the Company has to offer, and if it is the primary example PGE wants folks to consider when evaluating the ability of the Company to control costs, then it is relevant.

So let's look at PGE's AMI claims. Beyond the fact that AMI will not be completed until 2010 at the earliest, there are several problems with PGE's AMI claims.

i. PGE Claims $18.2 million in operational savings, but ignores the capital costs.

PGE cites $18.2 million in operational savings, beginning in 2010, when AMI is fully deployed. This is an impressive number, but is irrelevant, because rates will not go down $18.2 million. While the Company will reduce some costs by $18.2 million, this will be offset by other costs going up. In fact, in 2010, the year that PGE claims it will see $18.2 million in operational savings, PGE projects that customer rates will be $12.9 million higher than rates would be without AMI.[8]

The operational savings will be offset by rate base, return on rate base, accelerated depreciation of the old meters, and accelerated depreciation of the smart meters that PGE purchased after UE 115, all of this together resulting in higher rates in 2010. Over the full 20 years' life of the project, the Company projects actual net savings of $34 million, so the overall amount average annual savings is less than $1.5 million per year. This is out of a revenue requirement that is now over $1.8 billion per year (and growing fast). While we don't want to discount this -- every little bit helps – we note that PGE identifies this as "the largest component of cost savings identified in testimony."[9] When the largest component of savings PGE has identified is less than $1.5 million annually, and those savings won't begin for at least another 2 years, and even then won't save customers any money until some future year, then it is fair to conclude that the Company has failed to achieve significant cost savings related to its 2009 budget.

ii. AMI will cause a lot of customers to incur significant cost to repair the meter base.

CUB understands that the installation of AMI will require that some customers make repairs to, or replace, their meter base. In response to our data request, PGE

---

[8] UE 189/PGE/100/12.
[9] UE 197/PGE/100/13

suggests that this will happen to 0.03% of meters, or 254 customers.[10] However, PGE has provided a different projection to the vendor that PGE has hired to repair meter bases, but this other projection is confidential.

Begin Confidential Information

In its scope of work to the vendor, PGE says that meter base repairs will be required for up to [redacted] customers.[11]

In the non-confidential answer, PGE projects the cost of repair as follows:

> If the average cost of repairs is approximately $260 (see PGE's response to part (c)), then total costs would be approximately $66,000.[12]

These projections are based on:

> Estimated costs based on contractor quotes for a pre-existing need for repairs (not including permit costs) are as follows (see PGE's Response to CUB Data Request No. 105, Attachment 105-B):
>
> - $163 for replacement of socket clips for 200-amp meter base only.
> - $357 for replacement of the meter base only.[13]

It seems as though PGE took the average between the $163 cost of replacing the socket clips and the $357 cost of replacement of the meter base and arrived at an average cost of $260. However, the vendor's price quotes, which the Company has labeled confidential, suggest that costs could be considerably higher:

[redacted]

[10] CUB Exhibit 205.
[11] CUB Exhibit 206 confidential.
[12] CUB Exhibit 205.
[13] ibid.

[redacted]

CUB Exhibit 206, page 2.

PGE's projected cost was an average of the first two repairs, but if we average in the potential third repair the cost is obviously much higher. In addition, if the repairs require overtime, the labor cost is significantly higher. Finally, we note that PGE's project average cost of repairs is based on 2008 costs, and the costs will go up in 2009 and up again in 2010. It is during those years that most of the meter changes will occur and most of these costs will be incurred.

In answer to our data request, PGE projected the cost to customers for these repairs to be $66,000. Based on the information in CUB Exhibit 205 we project that the cost incurred by customers could be as high as [redacted].[14]

While this cost would be the responsibility of customers, and not part of PGE's revenue requirement, it could be a very significant amount. In addition, this cost could reduce the net benefits of AMI, over the full 20-year life of AMI, by more than [redacted].

End Confidential Material

We asked PGE directly if customers would be notified in advance if this risk to the meter base existed. This would allow the customer to ensure that PGE has current contact information for the customer, so the customer can authorize repairs in a timely manner and minimize the disruption of service. CUB Exhibit 207 is PGE's answer. While

---

14 [redacted]

PGE did not directly answer the question, the answer they gave makes clear that the Company expects that power will be shut off for many customers while it waits for them to authorize repairs.

The meter installer will attempt to notify the customer, but in many cases a customer could come home from work to find their power disconnected and a note on the door saying that they must make arrangements to repair the meter base before their power can be restored. In most cases, once the customer authorizes repairs, the repairs will happen in 24 hours. However, this situation will create problems for customers.

If PGE cannot notify the customer or property owner, the repair cannot begin. So in the case of someone who is on vacation, or a tenant who cannot make contact with a landlord, the household will experience a delay in service and will incur additional expenses, such as replacing food in a refrigerator or freezer.

So in a best case scenario, if a customer's power is turned off in the morning and PGE contacts that customer at a current daytime telephone number, that customer could authorize repair over the phone and by the time they get home their power might be restored by that evening. But many customers will be at work, with PGE not having the customer's current work number; therefore, it is likely that many customers will not know until they get home. At that time they will have to authorize the repair, and the repair will likely be delayed until the next day.

Low-income customers may not be able to immediately authorize hundreds of additional dollars in costs to make the repairs because they may not have the money. Even with PGE offering to pay for the repairs and then bill the customer, the customer still needs to be able to afford the repairs via an additional monthly payment.

iii. The savings PGE identifies assumes that the project will be done on time and on budget.

CUB worries that the meter base issue is just the first of several problems PGE will experience with AMI and that as we go forward, the costs will add up so that in the end the net cost savings from AMI will be far less than projected.

We asked PGE to provide us an update on actual costs versus projected. They provided us with status reports, but we note that the status reports provided to us are different than what was provided to the PUC.

CUB Exhibit 208 is an update on costs for the quarter ending March 31, 2008, and was supplied to the Commission as part of the Company's Quarterly Update required by the UE 189 order. CUB Exhibit 209 is a newer version of this same status report that was updated on 8/22/08, the day that we asked the Company for an update on its AMI costs.

The primary difference is that the original report filed with the Commission showed that the Company had spent nearly 40% of its Project Management budget and 40% of its O&M budget for the project, even though it is only just getting started. The revised report shows that the Company has spent little of its Project Management and O&M budgets. In its filing to the PUC, the Company reported that its actual cost through March 31st for Project Management of AMI was $4.5 million. In answering our data request, PGE says that its actual cost through March 31st of Project Management is $371,000, a reduction of more than $4 million. In its original filing with the Commission, PGE stated that its actual cost through March for O&M was $4.1 million. Now it is reporting that the actual cost was **zero;** again, this reduces the cost by more than $4 million. If PGE had reduced the cost of AMI by $8 million, this would be a good sign, but PGE's spending did not go down, PGE simply decided to limit the costs that were reported on:

> This report was revised for two purposes. 1. Previously reported budget and cost to date was for the entire PGE AMI Project. This revision reports only the portion of the project budget and cost tracked under the AMI Tariff. 2. Budget and cost to date were previously reported as loaded amounts. This revision reports unloaded budget and unloaded cost to date with loadings broken out on a single line (in above summary).

CUB Exhibit 209.

It should be noted that CUB's data request did not limit itself to "project budget and cost tracked under the AMI Tariff." More importantly, however, if PGE is only going to track the costs that were under the AMI Tariff, it makes the projected net benefits of AMI meaningless. Additional costs associated with AMI, whether old costs or new costs, will not be accounted for, because they were not part of the budget approved with the AMI tariff. In determining whether there is a net benefit associated with AMI, we must be concerned with the "entire AMI Project," but because PGE no longer tracks the "entire AMI Project," we will never know whether customers receive a benefit or not from AMI.

Whether there is a net benefit to AMI should be determined by looking at the total costs and benefits. From a customer perspective, whether a cost was incurred before or after the tariff is irrelevant. What is relevant is whether a cost was incurred, and whether it was charged to customers. If PGE's projection of $34 million net benefits over the next 20 years is based on the AMI Tariff approved by the Commission, we now know that there are $8 million in additional costs that are being ignored, so the net benefit now stands at $26 million. If the $34 million net benefits include these costs, then PGE should include them in its budget updates, so the Company's reporting is consistent with the benefit/cost case approved by the Commission.

III. PGE's Response to CUB's Proposed Adjustments

The only recommendation that CUB made that PGE accepted was a reclassification of costs for rate spread purposes. All other recommendations from CUB were rejected by PGE.

In our Opening Testimony, we proposed adjustments related to a number of items. PGE opposes all of our adjustments, but in every case PGE has failed to convince us that our adjustment should not be adopted.

A. Boardman Simulator

In our Opening Testimony, we recommending disallowing the costs associated with the Boardman simulator above $1.5 million. The budget for the Boardman simulator was revised upwards several times. Originally, the Company did a cost/benefit analysis of the simulator and found that its reliability benefits would reduce power costs and that the cost of the simulator was economical. However, PGE then revised its budget upwards without ever looking at whether the simulator would still be cost effective at the higher cost. The Commission should limit recovery to the amount that the Company found to be cost effective.

PGE disagrees with this, arguing that the project was never supposed to provide an economic benefit but was done for reliability purposes:

> The original version and the subsequent revisions of the project profile for the simulator at Boardman have always been approved on the basis of reliability. An economic valuation was performed in the original profile

> and subsequently updated in revision one of the project to understand what benefits in addition to reliability would be obtained from the simulator at that point; however the project was always pursued on the basis of reliability.

UE 197/PGE/1800/7.

The record clearly shows that this is not what happened. Originally, the project was focused on the cost of training, with reliability being an afterthought. After the budget grew significantly, the Company did a cost/benefit analysis that specifically modeled the reliability benefits.

CUB Exhibit 107 explains that the original project was developed in response to higher costs, while the Company believed there would be some reliability benefits, the driver for the simulator was the increase in training costs, not reliability:

> In the past, PGE sent Boardman employees off-site for training; however due to an uncontrollable change in service providers, the costs for Boardman training were expected to increase over 350%, from approximately $60,000 up to $272,000 per year. The initial proposal for the Boardman simulator was approved in August 2005 as a response to these increased costs and to maintain reliability.

CUB Exhibit 107/Jenks/1-2.

In February 2007, the project cost increased significantly and the Company conducted a cost/benefit analysis which then specifically looked at the reliability benefits. Confidential CUB Exhibit 108 from our Opening Testimony demonstrates this. PGE revised the data response that was the basis of Exhibit 107 on August 13. We include that update as CUB Exhibit 210. This updates shows that the company did additional modeling of the reliability benefits of the simulator as they revised the cost of the project. However, as we showed in our Opening Testimony, the Company did not update the economic analysis after the last revision raised the cost by $1 million.

It should be noted that when PGE first answered our data request, they did not include any modeling of economic benefits, even though we asked broadly for the information that was used to support the decision to pursue this expense. After their initial response, we had to complain to the Company that the analysis which was referred to in the data response was not included. They then provided the analysis. Now we find out that there was additional analysis that was not included in response to our original data request. This highlights a problem that we have had through recent cases with PGE, whereby it is difficult to get complete and timely responses to data requests which ask for the analysis behind decisions.

These increased reliability benefits that were part of PGE's analysis have been incorporated into the net power costs stipulation and will be passed through to customers. However, the project then increased by another $1 million after this projection and PGE decided not to revisit its cost/benefit analysis. There is no basis to find that this additional $1 million is prudent and provides a benefit.

The Commission faces a simple question. PGE made no attempt to justify this additional $1 million; they did not update their economic study; they did not revisit their analysis. Is saying the word "reliability" alone enough justification for charging customers $1 million?

B. Generation Excellence

In our Opening Testimony, we showed that we have tried to get PGE to provide some justification for the costs associated with the Generation Excellence Program. CUB Exhibits 116, 117, and 118 comprise the evidence that the Company was able to provide in support of the program. Ultimately we concluded:

> We asked PGE for all of its analyses of the Generation Excellence Initiative. We reviewed the materials PGE sent in response, and we found no financial justification for the Initiative. It seems that PGE did not perform any comprehensive cost-benefit evaluation of the overall Initiative. While PGE claims that these costs will improve plant performance and provide benefits to customers, outside of the financial analysis of the Boardman simulator, we found no analysis to support any financial benefit from these additional costs and employees.

CUB/100/Jenks/30.

In its Rebuttal Testimony, the Company responds by saying that CUB is mistaken:

> CUB is under the mistaken belief that all initiatives or projects must have a formal cost benefit analysis even if the primary motivation is another reason, such as reliability, or if the benefits are obvious. In the case of Generation Excellence, the primary motivation is two-fold: safety and reliability.

UE 197/PGE/1800/2.

PGE believes that as long as they claim safety and reliability that we must support it and the Commission must approve it. But that isn't the case. First of all, the distinction the Company is trying to make between economic benefits and reliability is a false one. If the program improves reliability of PGE-owned generating facilities, then it has an economic benefit. The Company can model that benefit as a reduction in Forced Outage Rates. However, if they quantify the benefits, then customers will rightly ask why we are being charged the costs of the program but are not receiving the economic benefits. Secondly, even if they cannot model the benefits, the Company should have some analysis of the program that supports it as a cost-effective program. CUB Exhibits 116, 117, and 118 are not analyses of the program that support the Company's claims of effectiveness; they are lists of actions and costs that the Company intends to take.

Finally, PGE states that while the cost of the program is $1.2 million in the test year, only $100,000 of that is incremental, meaning that PGE spent $1.1 million on this program in 2008.[15] We do not see that as a relevant point. This is the first rate case where this program could be evaluated. 2008 was not a test year. The Company cannot avoid a review of a program by beginning that program one year before a test year, so its costs are not incremental. This is our first chance to review this program and we found that the Company has failed to justify it. Therefore, they should not be allowed to charge customers for this program.

C. Helicopter

In our Opening Testimony, CUB agreed with PGE that its existing helicopter was ending its useful life; however, we disagreed with their economic analysis that justified purchasing a new helicopter. Because the actual use of the Company's helicopter was less than 150 hours per year, we took PGE's economic modeling and examined how it would change if we modeled 150 hours of usage rather than 250. We found that outsourcing the helicopter was lower cost and urged the Commission to reduce the Company's revenue requirement accordingly to remove the cost difference between outsourcing and purchasing a new helicopter.[16]

PGE recently sent CUB a revision to an earlier data response. This new response, provided as CUB Exhibit 212, states that the helicopter will not be used and useful in 2009. Based on this information, CUB is now asking that the helicopter be fully removed from ratebase.

[15] UE 197/PGE/1800/4.
[16] UE 197/CUB/100/37-38.

i. For how many hours does PGE need a helicopter?

PGE objected to our original adjustment. They argued that helicopter usage was low for in 2006 and 2007 because the helicopter was old and the pilot had health issues.[17] While we don't dispute this, it does not change the fact that PGE operated transmission system prudently during these two years with less than 150 hours of flights per year. CUB Exhibit 213 shows that the Company did not need to switch any inspection of lines to ground crews:

> PGE did not supplement inspections by helicopter with other means during 2006 and 2007 because we have some flexibility with inspecting transmission lines. At times, we are able to defer inspections. In 2008, helicopter inspections have been completed as scheduled.

CUB Exhibit 213

Instead, they were able to not conduct some flights and to defer some others. This year the Company plans to fly a total of 225-250 hours,[18] but this should include inspections that were deferred in the previous two years. Even with a supposed inspection backlog from deferring the inspections, PGE is saying that 250 hours is the maximum that the helicopter will be used in 2008. For the three years 2006, 2007 and 2008, the Company's total helicopter hours is expected to be between 515 and 525, or about 175 hours per year.

Essentially, PGE wants us to accept that prudent operations require a helicopter to be in use for 250 hours per year, but when it is not used that full amount, there are no operational consequences – no inspections are shifted to ground personnel, and there is no backlog that requires additional flights in the future.

[17] UE 197/PGE/1600/14
[18] ibid

At this point, there is no evidence that PGE needs a helicopter for 250 hours per year, other than PGE's own assertion. In addition, we know that in 2009, PGE will be using a helicopter that has maintenance issues, and has trouble flying 250 hour per year. Therefore we revise our recommendation and ask the Commission to reduce the helicopter usage to 175 hours in 2009, based on actual usage of the current helicopter in 2006 and 2007, and PGE's projection of usage in 2008.

ii. PGE's Revised Economic Analysis should be dismissed.

While the fact that the new helicopter will not be used in 2009, removes this as an issue from this case, we expect that it will be an issue in the future and we must respond to PGE's criticism of CUB's analysis of the purchase because it is obviously in error.

According to PGE, CUB's analysis was "too simplistic and fails to take into consideration the rigidity of the fixed costs involved in outsourcing a helicopter."[19] PGE claims that we assumed that all outsourcing costs are variable and they are not.[20] First of all, that is not true. We used the economic model which PGE provided us, and which they said was the basis for their analysis. It contained both fixed and variable costs. We simply made an adjustment in the hours that were being flown, and a similar adjustment in stand-by hours, believing that if the helicopter were used less, it would also be on stand-by less. All other assumptions in the model were PGE's.

In its Rebuttal, PGE claims that:

---

[19] UE 197/PGE/1600/17
[20] ibid

> Rogers Helicopter and Haverfield Corp. provided an annual outsourced fixed bid, which is based on annual availability of an aircraft and pilot; this is comparable to what we have with our in-house operation. These costs are fixed and do not vary with usage hours as CUB assumed in its analysis.

UE 197/PGE/1600/17.

PGE states that the Outsource cost would be the exact same if PGE used the helicopter for 150 hours as it would if PGE used the helicopter for 250 hours.[21]

	150 hours	250 hours
Rogers	9,703,346	9,703,346
Havenfield	11,311,367	11,311,367

This makes little economic sense. One primary cost of helicopter usage, whether owned or outsourced, is helicopter fuel. It would make little sense for a Company to contract to provide a helicopter to PGE and have no incremental cost associated with increased usage. Since the helicopter company incurs an incremental cost with usage, it would want that reflected in its price.

PGE includes the pricing information from Rogers as a confidential exhibit and this exhibit clearly shows both fixed and variable costs.

Begin Confidential Information

From PGE's own Exhibit, it is clear that the price is not fixed and that there would be a difference in price between using the outsourced helicopter for 150 hours and 250 hours.

Rogers Helicopter replied that they would charge the following:[22]

---

[21] UE 197/PGE/1600/17.
[22] UE 197/PGE/1604/1.

[redacted]

End Confidential Material

We do not know how PGE got from these price lists to the conclusion that there would be no price difference between using a helicopter for 150 hours and using one for 150 hours. Clearly, the price quotes they got back from the two bidders are a mix of fixed and variable costs which ensures that the cost of using an outsourced helicopter for 150 hours is less than the cost of using an outsourced helicopter for 250 hours.

D. Customer Focus Initiative

CUB recommended disallowing the cost of the Customer Focus Initiative because it provides little or no benefit to customers. The Design Team Report, which is more than 30 pages long, fails to mention minimizing customer rates, cost efficiencies, cost control or anything else that suggests PGE is attempting to build a corporate culture that rewards efficiency and cost control.[24]

PGE disagrees with us:

[23] UE 197/PGE/1600/17.
[24] CUB/100/25

> CUB implies that short-term cost efficiency should be the focal point for the Customer Focus Initiative. While we expect the Customer Focus Initiative will lead to some short term cost efficiencies, the program is designed to foster durable and sustainable improvements that will enhance reliability, service, and cost efficiency company-wide and over the long term. Cost efficiency is part of the basis for Customer Focus Initiative, but is not the entire justification.

UE 197/PGE/1700/8.

Once again, PGE cries "reliability," in a belief that if a program is done to improve reliability it must be approved. But this statement's real problem is that it creates a straw man to argue against rather than responding to CUB's testimony.

CUB did not say or imply that the focus should be on short-term cost efficiencies. We complained that there was <u>no</u> focus on cost efficiencies without any regard to short-term or long-term. CUB did not say that cost efficiency should be the "entire justification," only that it should be there in some meaningful way.

PGE goes on to criticize us for ignoring the "Facilitator's Guide," which has a couple of references in it to "price" and one reference to "value."[25] CUB believed that the document that described the program as designed was the more important of the two and focused on that one in our Testimony. Since PGE thinks that the Facilitator's Guide justifies this program, then we will place it on the record. CUB Exhibit 212 is the Facilitator's Guide.

A review of the Facilitator's Guide, just like a review of CUB Exhibit 106, the Design Team Report, demonstrates that the Customer Focus Initiative does not focus on cost control and efficiency in a meaningful way. If after reading those documents, the Commission believes that these are well-thought-out attempts to design a new corporate culture in a way that benefits customers, grant PGE recovery of the $300,000. If after

[25] UE 197/1700/9

reading them, the Commission believes, as we do, that this is a poorly designed program that lacks any real focus on cost control or other activities that benefit customers, disallow it.

E. Research and Development

CUB proposed a disallowance of $1.8 million for the Company's proposed R&D. This is a huge increase over the historical amount and simply is not justified.[26]

PGE disagrees with this adjustment. First they say that we were wrong, and that what we were relying on was a list of what PGE could have spent, and was provided simply to show the importance of R&D. [27] The information was from a data request sent out by the Staff, and it clearly asked for the 2009 budget. If PGE misstated this number in the data request, it should own up to it, and send out a corrected data response. Instead, the Company has admitted no mistakes and accuses CUB and Staff of ignoring PGE's explanations that we are using an "erroneous number."[28]

PGE then proposes to reduce its R&D budget to $500,000, which is still more than double the 7-year average. PGE proposes to allocate this to a series of specific research projects.[29]

CUB asked PGE to provide us with the analysis that supported each of these proposals. This analysis suggests that these programs are not well-thought-out.

One item on PGE's list is Distributed Energy Storage:

> PGE would focus on the use of rapidly evolving plug-in vehicles and high power density, deep cycle, advanced batteries. EPRI research in this area – especially in compressed air storage – would be reduced as would efforts around energy storage in ice. The overall impact involves deriving less

[26] UE 197/CUB/100/39.
[27] UE 197/PGE/1900/10.
[28] UE 197/PGE/1900/10.
[29] UE 197/PGE/1900/11-13.

> understanding and capability in using distributed energy storage opportunities to help with peak shaving and the intermittency associated with renewable power resources such as wind and solar.

UE 197/PGE/1900/12.

When we asked PGE about their analysis of this Distributed Energy Storage program and how customers benefit, we got a much different answer than the one above. CUB Exhibit 214 shows their response and includes this analysis of the Distributed Energy Storage and an explanation of how customers benefit:

> Attachment 117-B1 is a detailed research offering from EPRI covering the demonstration needs surrounding compressed air energy storage (CAES). PGE believes this a good example of the increasing awareness of the role distributed energy storage will have in (1) helping level peak power requirements; (2) providing minimum power "bridging" that would otherwise require turning on a large and expensive peaker power plant and (3) compensating for the intermittency of renewable power technologies such as wind and solar.
>
> Customers benefit from this research in the following manner:
>
> On their behalf, PGE assesses the viability, timeliness and cost-effectiveness of CAES technology as a form of distributed energy storage;
>
> - Should PGE support this specific EPRI demonstration, the Company would evaluate its potential for the Biglow Canyon wind power plant which would be in the range of power (20 to hundreds of MW) where this technology would have application;
>
> - The technology would be added to PGE's capability in helping "flatten" peak power demand. Although this example concerns CAES technology, the same arguments and cost / benefits would apply to any opportunity to store energy on a distributed model (e.g., via advanced, deep cycle lithium ion batteries in plug-in hybrid electric vehicles.)

This is their analysis that supports the funding of the program. It is primarily about compressed air energy storage (CAES). But what the Company says will actually be funded is something else: Plug-in Electric Vehicle Initiative – Charging Station Pilot Project

- Conversion of two hybrids w/ advanced battery
- New Electric Vehicle with advanced battery
- Joint Partnership w/ manufacturer[30]

PGE launched the plug-in hybrid charging station with great fanfare in July. According to the Oregonian article, the cost is supposed to be borne by the sponsor of the charging station, not customers.[31] Now we find out that PGE intends to charge customers through their R&D budget for charging stations. However, the analysis to support this R&D project is about compressed air storage, not plug-in hybrids.

Whether PGE is proposing to double, quadruple or increase sevenfold their R&D budget, makes little difference, they have failed to justify the increase with focused analysis, and it should be denied. CUB recommends that the Commission approve a R&D budget of $239,000 which is the average of what the Company has spent over the last 7 years.

F. Uncollectibles

In our Opening Comments, we pointed out that PGE is proposing to increase uncollectibles by $2 million, but fails to account for the fact that the Oregon Legislature had increased low-income bill payment assistance by 50%.[32]

---

[30]CUB Exhibit DR 117.
[31] CUB Exhibit 215
[32] UE 197/CUB/100/39.

PGE responds by arguing that energy assistance is not a dollar-for-dollar credit to PGE net write-offs. Further, PGE claims to be unaware of a relationship between energy assistance funding and uncollectibles:

> While one can theorize that there should be some relationship, it has not been quantified.

UE 197/PGE/1700/14.

CUB's point was simple. We know energy assistance funding is increasing by 50%. We can theorize that some of this will offset uncollectibles. PGE failed to take this into account at all. By not taking it into account, PGE has failed to justify its request for a $2 million increase. PGE has the burden to show that uncollectibles will increase by $2 million. Dismissing the increase in funding for low-income customers, because the relationship has not been quantified, does not disprove the relationship, it simply means that PGE has failed to show that a relationship does not exist. Since PGE did not take this new funding into account, their requested increase for uncollectibles should be denied.

G. Discretionary Reduction

In our Opening Testimony, we called for the Commission to order PGE to make a discretionary cut in its budget of 1%, "in light of PGE's lack of rigorous financial analysis and the Company's lack of aggressive cost management."[33]

i. If we cut costs, they go up.

The Company's Rebuttal Testimony is good evidence that this is necessary. To repeat: while PGE talks about controlling costs when times are tough for its customers, it has taken no actions to do so since filing this case and watching unemployment rise. In

[33] UE 197/CUB/ 100/32.

fact, in their rebuttal testimony, they cite the growing unemployment as a reason to increase the cost of uncollectibles.[34] So while PGE rhetoric seems to show empathy for customers during "tough" times, PGE actions suggest that a tough time for customers is simply one more reason to raise rates.

Instead of working to control its costs, PGE opposes reducing their costs and claims that such a reduction would be detrimental for customers. According to PGE, it is more important that we ensure that PGE is financially healthy:

> Over the next four years, we expect to need to finance over $1 billion. Most of this will go towards the construction of new generation facilities to serve customers and for retrofits of exiting generation to reduce our environmental impact. Weak financial conditions will increase our financing costs and thus the prices our customers see.

UE 197/PGE/1300/4

The only way to keep rates down in future is to give PGE the money it seeks now. This is not a helpful argument. We are proposing an adjustment that we do not believe will undermine PGE's financial condition, but will focus the Company on being more efficient. In addition, if we can get the corporate culture of PGE focused on cost control before they incur up to a billion dollars in additional costs, then we are more likely to save money on those investments.

PGE also opposed our adjustment by pointing out that discretionary cost reductions by the Commission in the past have been smaller.[35] We acknowledge that we are asking for a larger discretionary cut than the Commission has made in the past, but think the circumstances here require a more significant cut and a more significant message to the Company.

---

[34] UE 197/PGE/1700/11.
[35] UE 197/PGE/1300/32.

ii. There is only a single discretionary item in PGE's budget.

In their Rebuttal Testimony, PGE made the following claim:

> PGE has two categories of capital projects: base business and strategic. The target for base business projects is set considering factors such as the amount spent in prior years and price impacts. These projects are ranked based on a matrix of priorities and do not require individual price-impact analysis because it has been done in total. After jobs have been ranked, the overall target is reviewed considering the jobs 'on the edge'. Discretionary projects are not funded if the demand for capital exceeds availability. The strategic projects are much larger and are individually justified by relevant factors such as cost-benefit analysis.

UE 197/PGE/1300/22.

CUB asked PGE to see this matrix that Mr. Piro referred in his Testimony. We wanted to look both at what was funded and, just as importantly, what discretionary projects were rejected. CUB Exhibit 216 is the answer PGE provided. We note that they did not answer our request. Instead of showing us the matrix to which Mr. Piro referred, PGE provided us with a list of the projects that were funded. Mr. Piro stated that:

> After jobs have been ranked, the overall target is reviewed considering the jobs 'on the edge'. Discretionary projects are not funded if the demand for capital exceeds availability.

UE 197/PGE/1300/22.

This statement cannot be verified, because PGE did not provide the full matrix that was referred to in Mr. Piro's testimony. The number of discretionary projects, if any, that were not funded, cannot be determined.

CUB Exhibit 216 shows that a single discretionary project was funded in the 2009 budget. Of the 211 projects listed for 2009, PGE identifies a single one as discretionary. That one was an upgrade/replacement of the fitness equipment in the Tualatin Call Center. PGE management believes that none of the other 210 projects are discretionary.

PGE opposes our discretionary reduction. But PGE also claims that there is only a single discretionary item in this year's base business project capital budget. Out of a revenue requirement of $1.8 billion, the Company can only identify a single item that is discretionary. The only way to make some progress with this Company – the only way to get them to actually look at their costs in a serious attempt to identify cost reductions is to order them to do so. They will not do it voluntarily.

H. Employee Discount

The Company opposes proposals by CUB and ICNU to eliminate the Employee discount. PGE argues that because they compete with other utilities for employees they need the employee discount.[36]

If this were true, the employee discount would be part of the compensation study that PGE uses to compare their total compensation package to other utilities, but PGE does not include the employee discount in its compensation study. PGE studies the compensation needed to attract capable employees and then adds this on top of that compensation. It is not necessary. It is unfair and it insulates employees from the price signals related to PGE's service.

In addition, every time PGE raises its rates, this subsidy goes up.

The Commission should eliminate or phase out on a defined timeline the employee discount, at least to the degree that customers pay for it.

[36] UE 197/PGE/1500/28.

I. Decoupling

Ralph Cavanagh of NRDC agrees with our principle that decoupling should be tied to increased funding for energy efficiency.[37] However, we don't understand why he then goes on to say:

> Let's give PGE a chance to show what it can do when the barriers are removed and hold the company accountable if it fails, by making the extension of the mechanism contingent in part on energy efficiency results.

UE 197/PGE/2100/24.

Give PGE decoupling and give them 5 years to increase energy efficiency. This is like telling my daughter that she can have an allowance if she does certain chores around the house, but having the allowance will begin today and then, five years from now, she needs to show that she did her chores.

A better approach would be to tell the Company that decoupling will be considered when it is tied to additional energy efficiency programs. This is the approach that Oregon has taken with the natural gas companies. Decoupling clearly shifts additional risk to customers. This risk should be offset with additional benefits and the appropriate benefits associated with decoupling are additional energy efficiency programs that would not exist otherwise. If Mr. Cavanagh is right that this is going to happen anyway, then PGE will get its decoupling. But as Mr. Cavanagh admits, this was promised in the 1990s and did not happen. He cites the reasons energy efficiency programs were not expanded at that time and if additional programs are not proposed this time, there will no doubt be reasons for the lack of programs yet again.

[37] UE 197/PGE/2100/12.

The principle that decoupling should be linked to more energy efficiency programs is an important one to us, and requires a real link in real time to real programs. Allowing decoupling with a 5-year review, at which time the Commission can consider revoking it, if the Company has not implemented new energy efficiency programs, is not consistent with this principle.

We note that CUB has been a consistent supporter of decoupling before this Commission, but that support is based on utilities recognizing our principle of working toward maximum possible energy efficiency, and working within that framework. PGE has not. Pretending that PGE's proposal meets this principle, when it does not, is not helpful. Working with us to develop additional energy efficiency programs that would meet this principle, as the gas utilities did, would be a helpful approach to decoupling.

Finally, while we do not disagree with PGE's statement that it did not pay for Mr. Cavanagh's testimony and "that he is completely independent (as anyone who knows Ralph can attest),"[38] we think that PGE should have disclosed that it is making a substantial contribution to Mr. Cavanagh's organization, NRDC. CUB Exhibit 217 shows that PGE is paying the salary of Pamela Lesh, who is on loan to NRDC.

IV. Staff's Rate Design

The staff proposed a new rate design which would add a seasonal summer block to residential customers.[39] While we appreciate that the staff did not propose full seasonal rates for residential customers, we still must oppose their proposal.

---

[38] UE 197/PGE/1300/35.
[39] UE 197/Staff/500/14-18.

Customers do not want time-of-use or seasonal rates. Customers have a time-of-use option and it is not widely used. In other industries, such as wireless phones, we have seen customers move away from time differentiated rates. In a nutshell, most customers don't want to think about different rates for different usage patterns.

CUB has supported tiered rates. They have a long history in Oregon, going back to Oregon Fair Share's advocacy for Lifeline Rates in 1981. But these rates are constant and while they change with usage, they do not change from hour to hour or month to month. Quite frankly, we do not believe that the hassle is worth the result or the potential risk to customers. While economists like price signals, most customers are too busy in their daily lives to respond in a way so as to optimize each economic decision. But there will be some customers who will notice and will want an explanation each year when their rates change as we enter the summer months.

If the Commission is inclined to add a third pricing block, we would recommend that such a block be done on an annual basis. This will allow these rates to be stable. It will remove the need to change prices an additional two times per year. The change in rates will only have the desired effect if it is well advertised so customers are aware of it. Having it be well-advertised, of course, will increase the amount of time that we, and the PUC, spend explaining to customers why their rates have changed.

V. Marginal Cost

First, we are a little surprised over the number of recommendations to change PGE's marginal cost study, and surprised at PGE's offer of a compromise over the issue of short-run marginal costs for generation, since this was an issue that PGE took a strong stand on a few years ago. Both Staff and ICNU propose changes to PGE's marginal cost study.

In Oregon, we use marginal cost studies as a guide for allocating the costs of an embedded, historical system. The theory is that using marginal costs will send better price signals to customers, since it is assumed in a competitive market that marginal cost is the basis for setting prices. The problem with this theory is that we are not setting prices at marginal cost, because doing so would deprive Oregon customers of the benefits of the ratebase that we have funded for decades. Instead, we use marginal costs as a guide for allocating the actual costs of the utility system.

In theory this sounds like a reasonable idea. However, in reality it requires many judgments that shift costs between customer classes. Some are much removed from how the utility system really operates. On the distribution system, we must theoretically construct a new system from scratch to project the marginal cost of wires, poles, meters, line drops, and other equipment. We then must find a theoretical approach to allocating the costs of this distribution system between customer costs, demand-design costs, demand costs, and energy costs. This requires us to ask silly questions, such as how much of the cost of a power line is necessary to serve a customer if that customer put no actual load on the system. While no utility would build a system to serve customers without demand, we ask this question to identify the amount of the distribution system that is assigned as a customer cost. In order to do this, we have to adopt an approach to assigning costs. For the distribution system, there are three primary approaches: the minimum system approach, the zero intercept approach, or the facilities approach. Once we have chosen an approach we must make dozens of decisions about how to apply that approach.

We must make similar judgments about the transmission and generation system. In the end we come up with a system of cost-allocation that involves dozens and dozens of judgment calls, all of which can be challenged by good arguments (or conversely, all of which are supported by poor arguments). While we can debate each individual judgment, the ultimate test is whether the overall results are reasonable or not.

In the 1990s we had a debate about these in nearly every ratecase, until the Commission authorized UM 827 to look generically at marginal cost issues. That docket did not reach a consensus. CUB certainly does not support the approach to cost allocation that has been taken since that docket. But we did achieve some resolution. CUB, which had taken the lead in challenging the cost allocation, stopped doing so, because after UM 827, the issues were largely settled. We disagreed with the approach the utilities advocated and the Commission adopted, but we had little choice but to accept it.

Now a number of parties are proposing changes to the cost allocation approach. We think this raises several issues: Does the allocation methodology we use lead to a fair result? Are the proposals by ICNU and Staff reasonable? And what about Staff's proposal to hold workshops on marginal cost issues?

A. Are the results of PGE's marginal cost study, and the rate spread which comes out of it, reasonable?

While each individual judgment in the marginal cost study can be contested, it is worth first looking at the overall result to see if customers are getting a fair allocation of cost. A good way to do this is to compare the results of cost allocation in Oregon, with allocation results for our neighbors in the State of Washington. Instead of using marginal costs, Washington uses an embedded cost approach to cost allocation. They attempt to take each cost in the utility's revenue requirement and allocate it to customer classes based on cost causality: which class of customers caused the cost to be incurred. This is a significantly different approach that does not require the construction of a theoretical utility system, and therefore gives us a good point of comparison for our more theoretical approach.

CUB Exhibit 218 shows the results of this comparison. It shows that Oregon allocates significantly more costs onto residential and commercial customers than Washington does, and considerably fewer costs are allocated to industrial customers in Oregon than in Washington. This suggests that it is residential customers who are allocated costs that are too high in Oregon. This is consistent with the analysis that CUB did in the 1990s that led to UM 827.

Table 1: Rates, April 2008 (cents/kWh)

[40]	Residential	Commercial	Industrial
Oregon	8.57	8.2	4.41
Washington	7.49	6.88	5.2

[40] UE 197/PGE/2000/7

B. Are the proposed changes in marginal cost methodology reasonable?

Staff proposed that the Commission accept PGE's marginal cost study because they "find the overall results to be reasonable." ICNU on the other hand, proposes several significant changes to the methodology. CUB largely agrees with PGE's response to ICNU's first 3 critiques of PGE's marginal cost analysis:

- Adding estimates of hourly load shape for each individual rate schedule would complicate the study, but not improve it;
- PGE's cost of service study includes capacity and reserves; and
- Historical fixed costs do not belong in a marginal cost study.[41]

However, we disagree with PGE's response to ICNU over the use of short-term marginal cost estimates for generation cost. On the one hand, PGE defends their approach, but at the same time offers an alternative approach that blends short-term and long-term marginal cost.

This is a dramatic change from where PGE was in UM 827. At that time PGE was a leading proponent of using short-term marginal cost pricing for generation costs. In proposing an alternative to this approach, PGE fails to address the theoretical basis for its advocacy of short-term pricing for generation costs. CUB Exhibit 218 is a paper written by Dr. Hethie Parmesano, of NERA, who was PGE's outside expert on marginal cost issues in the 1990s. In it, she concludes that "marginal cost pricing based on LRMC [Long Run Marginal Cost] is efficient only by coincidence."[42]

At that time, ICNU was also a supporter of using short-term marginal cost for generation. They advocated simply using market prices:

---

[41] UE 197/PGE/2000/12-13.
[42] CUB Exhibit 219, pages 11-12.

> The results of information from the vigorous Northwest nonfirm markets should be used in developing energy costs on a time of day and season of year basis. For example, the Northwest nonfirm market prices, as reported in Clearing Up, or Mid-Columbia prices reported in various publications, could provide better indications of marginal costs of energy than a theoretical model could predict.

UM 827, ICNU, Direct Testimony of Lincoln Wolverton, page 7.

CUB does not support either ICNU's proposed changes in generational marginal cost or PGE's proposed "compromise." Neither party has addressed the theoretical basis that led PGE to adopt the current approach, nor has either provided data that convinces us that changing the approach will lead to more reasonable overall costs.

C. Staff proposes workshops to examine marginal cost.

The Staff proposes that the Commission "direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for developing marginal cost estimates."[43] PGE states that it is willing to meet with parties and a request from the Commission is needed, not an order.[44]

CUB agrees that it is worth a review of PGE's marginal cost methodology. We continue to believe that it leads to results that place too great a share of the costs of the system on residential customers. In addition, we note that marginal cost methodology has not undergone a significant review in more than a decade. Here is what we had to say then:

> Periodic review allows the Commission to focus on the general role of marginal costs in the ratemaking process, and updates the marginal cost analysis as conditions warrant. As OCEUR notes, the last such review was over a decade ago. This fact alone suggests that the item is ripe for reconsideration. Such reconsideration should take place in a generic, not ratecase, proceeding, so that the Commission can focus on the general role

[43] UE 197/Staff/600/6.
[44] UE 197/PGE/2000/10.

> of marginal costs in the ratemaking process of all utilities without the pressure of immediately setting rates for a particular utility.
>
> A generic docket for all utilities is a cost-effective and efficient way to review marginal costs, both for the Commission and for the various intervenors.

CUB's Reply to OCEUR Motion to Vacate Investigation, pages 1-2.

Costs of Service studies are highly technical. Staff's proposal to open workshops, outside of a docket, would restrict customer groups from using intervenor funding to hire experts with sufficient technical knowledge. CUB believes a review is a good idea, but we would prefer to have such a review happen as part of a new generic docket, and for the parties to bring sufficient technical knowledge to the table to justify the time spent.

VI. Conclusion

PGE filed this case in February. Since that time, CUB and other parties have conducted discovery on PGE, we have had settlement discussions, we submitted our Opening Testimony, and PGE submitted Rebuttal Testimony. Each step of the way has reinforced our concern that a lack of good cost control and cost review is the primary factor driving this case.

CUB recommends that the Commission:

- Adopt the labor adjustment proposed by CUB-ICNU witness Ellen Blumenthal.
- Impose a 1% of overall revenue requirement cost reduction, approximately $17 million, in light of PGE's lack of rigorous financial analysis and the Company's lack of aggressive cost management.
- Remove the costs associated with the Generation Excellence Program, which PGE has been unable to justify. If the Commission adopts accepts Ms.

Blumenthal's labor adjustment, then it should remove the non-labor portion of the program. If the Commission rejects her labor adjustment, then it should remove the entire cost of the program.

- Since PGE was only able to justify the first $1.5 million associated with the Boardman simulator, the Commission should disallow the additional $1 million from rate base.
- The Customer Focus Initiative offers little or no benefit to customers and its $300,000 cost should be removed from rates.
- Because PGE's new helicopter will not be used and useful in 2009, it should be entirely removed from rate base. In addition, the Company's revenue requirement should reflect using its existing helicopter for 175 hours in 2009.
- PGE has failed to support its proposal to more than double its R&D budget. The budget should be set at $239,000, the average amount that PGE has spent on R&D over the last seven years.
- PGE's request to increase its uncollectibles budget by $2 million should be rejected, because PGE failed to consider the impact that increased low-income bill payment assistance will have.
- PGE's employee discount should be eliminated or the Commission should set a strict schedule to phase out its inclusion in customer rates. It is not justified and is not necessary to compensate PGE employees, and it inappropriately insulates Company employees from rate increases.
- PGE's decoupling proposal should be rejected, because it does not contain a real-time link to energy efficiency programs.

- The Staff's proposal to add a new rate block for residential customers should be rejected.
- ICNU's marginal cost proposals should be rejected. There is no evidence that PGE's cost allocation does not lead to a fair result for industrial customers. Instead, the Commission should open a generic docket to consider issues related to cost of service and rate spread.

WORKSOURCE OREGON
EMPLOYMENT DEPARTMENT

News

State of Oregon • Employment Department • 875 Union NE, Salem, OR 97311 • www.QualityInfo.org

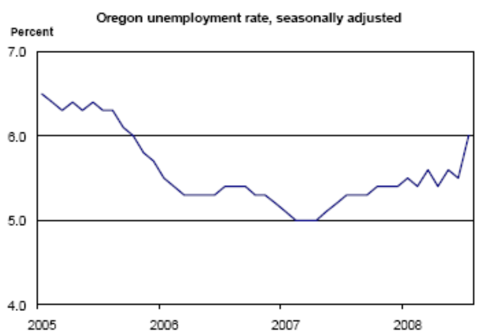
FOR IMMEDIATE RELEASE: August 11, 2008

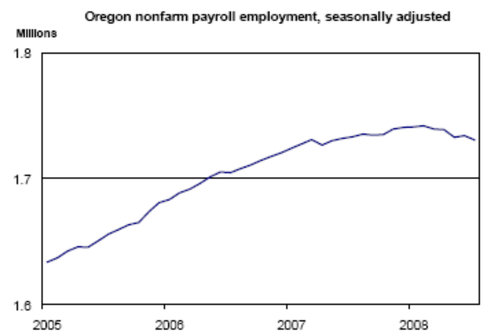
CONTACT INFORMATION: Art Ayre, State Employment Economist, (503) 947-1268

Oregon's Employment Situation: July 2008

Oregon's seasonally adjusted unemployment rate rose from 5.5 percent in June to 6.0 percent in July. The U.S. seasonally adjusted unemployment rate rose from 5.5 percent in June to 5.7 percent in July.

In July, Oregon's seasonally adjusted nonfarm payroll employment fell by 3,600, following a gain of 1,400 in June.





Industry Payroll Employment (Establishment Survey Data)

In July, total seasonally adjusted payroll employment dropped by 3,600, the fourth monthly job loss over the past five months. Payroll employment stood at 1,730,600, which is 11,300 lower than the peak reached in February. This job loss over the most recent five months is equal to 0.6 percent of nonfarm payroll employment and has averaged 2,300 per month.

In July, three major industries posted substantial seasonally adjusted job losses: construction (-1,200 jobs); manufacturing (-2,400); and educational and health services (-1,100). Meanwhile, professional and business services added 2,200 jobs and was the only major industry sector to post a substantial monthly job gain.

Construction added only 1,700 jobs, which was less than the expected seasonal gain of 2,900 for July. Most published industries within construction added a modest number of jobs for the month. One exception was building equipment contractors, which added 1,500 jobs. Heavy and civil engineering construction cut 600 jobs in July and is down 1,900 jobs since July 2007.

— more —

Construction employment is down 10,000 jobs or 9.1 percent since July 2007.

Manufacturing added only 300 jobs in July, at a time of year when the expected gain was 2,700. Manufacturing has seen a substantial contraction over the past 12 months, shedding 8,800 jobs in that time. The losses have been predominantly in the durable goods sector, which is down 9,600 jobs since July 2007.

In July, most of the industries within durable goods were flat. The exception was transportation equipment manufacturing, which lost 900 jobs. Transportation was hit by rapidly dropping demand in the motor coach manufacturing sector this year.

Nondurable goods manufacturing added 900 jobs in July and was up 800 over the year. This sector was aided by the addition of 500 jobs in food manufacturing.

Educational and health services posted a rare seasonally adjusted job decline in July. The sector reported 3,400 fewer jobs, which was below the typical July loss of 2,300. Despite the one-month dip, the industry has been growing rapidly and steadily for many years. Employment is up 9,500 jobs or 4.6 percent since July 2007.

Professional and business services was the lone major industry sector adding many jobs on a seasonally adjusted basis in July. Its gain of 2,200 was more than the normal flat trend for the industry in July. The gain for the month puts the industry back on its track of slow growth over the prior two years. Since July 2007, the industry has added 2,300 jobs or 1.2 percent.

Two positive trends were seen in July within administrative and support services: Employment services added 700 jobs, and services to buildings and dwellings added 800 jobs.

Unemployment (Household Survey Data)

In July, Oregon's seasonally adjusted unemployment rate rose by half a percentage point in one month to reach 6.0 percent. Thus, the state's rate has risen by a full percentage point since reaching a recent low of 5.0 percent in February through April 2007.

In July 114,032 Oregonians were unemployed, an increase of 13,401 compared with July 2007 when 100,631 were unemployed.

The Oregon Employment Department will release statewide unemployment rate and employment survey data for August 2008 at 11 a.m. on Monday, September 15, 2008.

— end —

For the complete version of the news release, including tables and graphs, visit: www.QualityInfo.org/pressrelease.

For help finding jobs and training resources, visit one of the state's WorkSource Oregon Centers or go to: www.WorkSourceOregon.org.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 110

Request:

PGE/1400/5 lists a number of adjustments to its test year budget that reduce PGE's revenue requirement. All these reductions relate to costs that are contested by PUC Staff. Since filing its original case, has PGE identified any savings in its budget that does not relate to the partial settlement or to PUC Staff adjustments?

Response:

The request is based on an incorrect premise. Several of the proposed reductions do not represent company savings but rather remain costs that PGE will continue to incur even though the costs are excluded from the final revenue requirement for the 2009 test year.

PGE is currently developing its 2009 budget which may identify additional costs or savings compared to the 2009 test year forecast. However, it has not been completed. For additional information regarding savings, see PGE's response to CUB Data Request No. 102.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 102

Request:

Mr. Piro (PGE/1300/17) states that "CUB's assertion, that PGE could only identify a small list of cost savings measures in its initial rate case filing, assumes that the examples given were the only measures taken. That simply is not the case and seriously distorts the company's operations." Please identify all other cost savings that impact the test year.

Response:

PGE has identified savings in the following dockets:

- UE 180, PGE Exhibit 500, pages 3-4.
- UE 197, PGE Exhibit 100, pages 11-15.
- UE 197, PGE Exhibit 1300, pages 14-15.

PGE has not performed additional analyses to identify every savings or avoided cost associated with each capital job or O&M project that PGE has undertaken in the recent past that could have impacted the test year in one form or another. One reason is that, as noted in PGE Exhibit 1300, page 21, many projects or costs are necessary by regulatory or service requirements, or have minimum discretionary components. Another reason is that numerous projects do not have easily quantifiable benefits. In addition some projects provide needed capabilities that existing systems do not. Again, the benefits may be difficult to quantify, but are fully valid.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 108

Request:

Please provide a quarter-by-quarter comparison of the budget for AMI versus the actual cost incurred, since January 2007. In this comparison, please separately identify all major project categories (project management, IT…). Please explain any discrepancies between actual costs incurred versus budgeted.

Response:

PGE objects to this request as seeking information that is neither relevant nor likely to lead to the discovery of admissible information. AMI costs are not part of this rate case. Subject to and without waiving it objection, PGE responds as follows:

Attachments 108-A and 108-B provide copies of PGE's first and second quarter 2008 status reports for AMI. These attachments reflect O&M costs incurred after June 1, 2008 (in relation to the AMI tariff, as requested by OPUC Staff) and all capital costs from the beginning of the project. Attachment 108-C lists actual O&M costs from July 1, 2007 through May 31, 2008, the period covered by UM 1328 and approved by Commission Order No. 08-209. Attachment 108-D provides PGE's initial budget for July 2007 through May 2008, as filed with the UM 1328 application.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 103

Request:

Mr. Piro (PGE/1300/18-19) lists AMI as "the largest component of costs savings identified in testimony." With regards to AMI:

a. Does the "NPV of approximately $34 million, include any estimate of the cost to customers of fixing meter bases that will be damaged in the installation of AMI?
b. Does PGE have any estimates of the total cost to all customers of repairing the damage to meter bases?
c. Does PGE have any estimates of the cost to an individual customer of repairing the damage to his or her meter base?
d. Please provide any reports, memos, or analysis that PGE has which relate to the problem of meter base damage due to installing AMI.

Response:

a. AMI installation is **not** expected to result in damage to the meter base, but could reveal any damage or need for repairs that **already** exist. PGE did not include any costs related to repairing meter bases in our AMI financial analysis. If PGE were to cause damage during AMI installation, we would incur the repair costs as current year O&M expense. To date, PGE has installed 3,150 AMI meters and has only experienced one instance where the customer's equipment was in need of repair due to a pre-existing condition.

b. See PGE's response to part (a), regarding damage caused as a result of AMI installation. PGE does not have an estimate of the total cost to all customers based on a pre-existing need for repairs because we do not know in advance how many customers will require repairs. As noted in PGE's response to part (a), 0.03% of meters to date have required repairs. If this ratio were to continue, then approximately 254 meters out of 800,000 would require repairs based on pre-existing conditions. If the average cost of repairs is approximately $260 (see PGE's response to part (c)), then total costs would be approximately $66,000.

c. See PGE's response to part (a), regarding damage caused as a result of AMI installation. Estimated costs based on contractor quotes for a pre-existing need for repairs (not including permit costs) are as follows (see PGE's Response to CUB Data Request No. 105, Attachment 105-B):

- $163 for replacement of socket clips for 200-amp meter base only.
- $357 for replacement of the meter base only.
-

d. See PGE's response to part (a).

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 107

Request:

Does PGE have any plans to inform customers in advance that AMI could lead to damage the meter base which would require shutting off electricity until the customer authorizes repairs? If so, please provide the plans. If not, why not.

Response:

AMI installation is **not** expected to result in damage to the meter base, but could reveal any damage or need for repairs that **already** exist. PGE did not include any costs related to repairing meter bases in our AMI financial analysis. If PGE were to cause damage during AMI installation, we would incur the repair costs as current year O&M expense. To date, PGE has installed 3,150 AMI meters and has only experienced one instance where the customer's equipment was in need of repair due to a pre-existing condition.

If PGE does identify a meter base with existing damage or need for repairs, we will notify customers as follows:

1. The on-site meter installer will attempt to contact an occupant of the premise and inform them of needed repairs and whether service will be disconnected for safety reasons.

2. If no face-to-face contact is made at the premise, the meter installer will leave an informational door hanger detailing what was found and the customer equipment in need of repair. The door hanger will inform the occupant if service has been or is scheduled to be disconnected due to safety reasons. The door hanger will include a local and toll-free number to a PGE field coordinator who will provide detailed information to the property

owner about needed repairs, including the opportunity to use a contractor recommended by PGE as described in PGE's response to CUB Data Request No. 105.

3. A PGE field coordinator will attempt to contact the property owner by phone if no face-to-face contact is made at the premise to inform them of needed repairs to the customer-owned equipment, as well the opportunity to use a contractor recommended by PGE as described in PGE's response to CUB Data Request No. 105.

PGE Advanced Metering Infrastructure

Quarterly Report to the OPUC

For the quarter ending March 31, 2008

Advanced Metering Infrastructure (AMI) Project

Summary: This project carries out activities to deploy a two-way, fixed-network AMI system throughout PGE's service territory. Scope includes project planning, IT readiness, vendor selection & contracting, business process development, system acceptance testing, deployment of 852,000 meters and related radio-frequency (RF) communications equipment, and evaluation of certain customer & systems-related benefits.

Project Start Date	Project Completion Date	# of AMI Meters Deployed to Date	# of Meters Read by Network for Billing	JMR Routes Remaining with PGE	JMR Routes Remaining with NNG
August 2005	September 2010	0	0	1,691	568

Project Cost Summary	AMI Project Budget	Actual Cost to Date	Remaining Cost to Complete
Meters	$ 107,698,170	$ 126,977	$ 107,571,193
IT	10,425,171	1,469,068	8,956,103
Network	7,059,223	233,356	6,825,867
Business Processes	6,067,900	1,486,375	4,581,525
Project Management	12,940,128	4,456,968	8,483,160
Capital Sub-total	132,231,273	3,715,370	128,515,903
O&M Total	11,959,319	4,057,374	7,901,945
Total Project Costs	**$ 144,190,592**	**$ 7,772,744**	**$ 136,417,848**

Variance Explanation: On schedule, with no changes to scope or variances to project budget.

Project Milestones	Due Date	Status
▪ Begin System Acceptance Testing (SAT)	06/02/2008	16,000 meters to be deployed for functionality & end-to-end testing
▪ Complete System Acceptance Testing	12/31/2008	Final stages of test design and planning
▪ Begin Mass Meter Deployment	01/05/2009	Preliminary month-to-month deployment schedule prepared
▪ Complete RF Network Installation	12/31/2009	RF propagation study and tower location analyses nearing completion
▪ Complete Mass Meter Deployment	09/12/2010	To be followed by up to six-month system optimization process

Project Job Status	Due Date	Budget		Costs to Date	
		Capital	O&M	Capital	O&M
Meter Installation – SAT	09/2008	7,674,471	-	126,977	-
Meter Installation – Full Deployment	09/2010	100,023,699	-	0	-
Meters Subtotals – Capital / O&M		*107,698,170*	-	*126,977*	-
Meters – Total		**107,698,170**		**126,977**	
IT Infrastructure Support	09/2010	4,550,424	795,639	1,041,714	614
MDC – General AMI Requirements	01/2010	-	347,402	-	80,375
MDC – CS SAT Testing	12/2008	-	198,130	-	54,941
IT AMI Software	06/2010	2,387,406	15,501	163,246	-
Interval Date Storage & Usage	11/2009	2,130,669	-	128,178	-
IT – Subtotals – Capital / O&M		*9,068,499*	*1,356,672*	*1,333,138*	*135,930*
IT – Total		**10,425,171**		**1,469,068**	
Host System Installation – SAT	05/2008	500,000	-	233,356	-
Host System Installation – Full Deployment	12/2008	700,000	-	-	-
Tower Site Deployment	12/2009	5,122,821	736,402	-	-

PGE Advanced Metering Infrastructure

Quarterly Report to the OPUC

For quarter ending March 31, 2008 REVISED on 8/22/08

Advanced Metering Infrastructure (AMI) Project

Summary: This project carries out activities to deploy a two-way, fixed-network AMI system throughout PGE's service territory. Scope includes project planning, IT readiness, vendor selection & contracting, business process development, system acceptance testing, deployment of 852,000 meters and related radio-frequency (RF) communications equipment, and evaluation of certain customer & systems-related benefits.

Project Start Date	Project Completion Date	# of AMI Meters Deployed to Date	# of Meters Read by Network for Billing	JMR Routes Remaining with PGE	JMR Routes Remaining with NNG
August 2005	September 2010	0	0	1,691	568

Project Cost Summary * Unloaded and Rounded to Nearest Thousand	AMI Project Budget*	Actual Cost to Date*	Remaining Cost to Complete*
Meters	$ 106,262,000	$ 127,000	$ 106,135,000
IT	7,902,000	1,140,000	6,762,000
Network	6,249,000	225,000	6,024,000
Business Processes	3,912,000	857,000	3,055,000
Project Management	7,245,000	371,000	6,874,000
Capital Sub-total	126,361,000	2,720,000	123,641,000
O&M Total	5,209,000	0	5,209,000
Total Unloaded Cost	**$131,570,000**	**$2,720,000**	**$ 128,850,000**
Loadings	7,548,000	995,000	6,553,000
Total Loaded Costs	**$ 139,118,000**	**$ 3,715,000**	**$ 135,403,000**

Variance Explanation: This report was revised for two purposes. 1. Previously reported budget and cost to date was for the entire PGE AMI Project. This revision reports only the portion of the project budget and cost tracked under the AMI Tariff. 2. Budget and cost to date were previously reported as loaded amounts. This revision reports unloaded budget and unloaded cost to date with loadings broken out on a single line (in above summary).

Project Milestones	Due Date	Status
▪ Begin System Acceptance Testing (SAT)	06/02/2008	16,000 meters to be deployed for functionality & end-to-end testing
▪ Complete System Acceptance Testing	12/31/2008	Final stages of test design and planning
▪ Begin Mass Meter Deployment	01/05/2009	Preliminary month-to-month deployment schedule prepared
▪ Complete RF Network Installation	12/31/2009	RF propagation study and tower location analyses nearing completion
▪ Complete Mass Meter Deployment	09/12/2010	To be followed by up to six-month system optimization process

Project Job Status	Due Date	Budget *		Costs to Date *	
		Capital	O&M	Capital	O&M
Meter Installation – SAT	09/2008	7,456,000	0	127,000	0
Meter Installation – Full Deployment	09/2010	98,806,000	0	0	0
Meters Subtotals – Capital / O&M		*106,262,000*	*0*	*127,000*	*0*
Meters – Total		**106,262,000**		**127,000**	
IT Infrastructure Support	09/2010	4,237,000	646,000	866,000	0
MDC – General AMI Requirements	01/2010	0	24,000	0	0
MDC – CS SAT Testing	12/2008	0	0	0	0
IT AMI Software	06/2010	1,691,000	7,000	148,000	0
Interval Date Storage & Usage	11/2009	1,297,000	0	126,000	0
IT – Subtotals – Capital / O&M		*7,225,000*	*677,000*	*1,140,000*	*0*
IT – Total		**7,902,000**		**1,140,000**	

August 13, 2008

TO: Lowrey Brown
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE *Second Supplemental* Response to CUB Data Request
Dated May 19, 2008
Question No. 049

Request:

PGE in investing in a new training simulator and expanding the staff related to training at Boardman.

a. **Please provide a copy of the proposals (analyses, memos, and all other documentation) that was consider by Jim Piro, the Officers, and the Board of Directors concerning this new training program.**
b. **How does this group benefit customers?**
c. **If the Company has engaged in multi-year planning for this group, does PGE forecast the amount of company resources invested in this program to increase, decrease, or remain the same in the next few years?**
d. **What is the total cost in the 2009 test year related to the training simulator and training at Boardman (please distinguish between the two), and how does this compare to the cost before PGE purchased the simulator.**

Response:

a. PGE objects to this request on the basis that is it overly broad and unduly burdensome. Without waiving its objection, PGE replies as follows: Please see PGE Attachment 049-A, which is the internal project profile used by the Capital Review Group. Attachment 049-A is confidential and subject to Protective Order 08-133.

b. Training for plant staff is critical to maintain high reliability. In the past, PGE sent Boardman employees off-site for training; however, due to an uncontrollable change in service providers, the costs for Boardman training were expected to increase over 350%, from approximately $60,000 up to $272,000 per year. The initial proposal for the Boardman simulator was approved in August 2005 as a response to these increased costs and to maintain plant reliability. After Revision 1 in August 2006 the project had a 4.88 year payback period. In February 2007, PGE increased the project cost by an additional $0.6 million for the simulator and a further $0.4 million to increase the size of the building for Boardman offices and storage. With these additional costs, the project was not expected to have an economic payback of less than 5 years; however, it was still considered a critical part of training, reliability and safety. The project justification is also described in PGE Attachment 049-A.

c. The total costs in 2009 represent a consistent level of PGE's current plans for on-going costs.

d. The total cost for training at Boardman in years 2005 through 2009 are presented below:

Year	Dollars	% Change
2005	282,000	
2006	251,000	-10.99%
2007	333,009	32.67%
2008	176,155	-47.10%
2009	184,926	4.98%

* Includes PGE's share of labor and non-labor

Supplemental Request June 13, 2008

On June 13, 2008, CUB requested the economic analysis provided to support version 3 of the project approval.

Supplemental Response June 13, 2008

Related to the payback analysis discussed on page 3 of Attachment 049-A:

As discussed in part b above, the final version of the project was approved for reliability purposes, not on economic payback, and therefore the payback analysis was not included in the final project approval and, subsequently, was not included in PGE's response. The original payback analysis is PGE Attachment 049 Supp 1-B.

Second Supplemental Response August 6, 2008

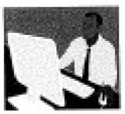
In preparing PGE's rebuttal testimony, PGE reviewed the individual revisions of the Boardman Simulator Project profile for a job and ranking code. During that review, we discovered that the final project profile, Revision 3, provided to CUB in PGE's Response to Data Request 049, did not include all of the detail from the previous versions. Specifically, version 0 of the project profile included an original economic analysis, but this information was removed in revision 1.0 to avoid confusion because the results were no longer valid. The economic analysis in version 0 was a preliminary analysis that was then updated in revision 1.

PGE Attachments 049 Supp 2-C, D and E provide revisions 0, 1, and 2. PGE Attachment 049 Supp 2-F is the economic analysis for version 0. These do not change the final conclusions of the revisions already provided, but only include the additional analysis described above. Attachments 049 Supp 2-C, D, and E are confidential and subject to Protective Order 08-133.

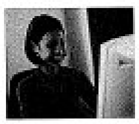
g:\ratecase\opuc\dockets\ue-197\dr_in\cub_pge\finals\dr_049_supp 2.doc

CUB/211
Jenks/1

facilitator's guide



Customer Focus
Orientation 2007



good to great

On Customer
Satisfaction

PGE
INITIATIVE

Version 1.

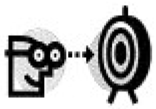
Attachment 029-B

Customer Focus Initiative

Orientation Workshop

QUOTES

There are no business results inside an organization. There are only costs and efforts. All the results occur on the outside when customers convert those costs and efforts into revenues and profits. ***...adapted from Peter Drucker***



Line of Sight

Voice of the Customer

An entire organization, every nook and cranny, is about creating value for customers. This is what stimulates and excites the company. Otherwise the company is merely a series of pigeonholed parts with no consolidating purpose or direction. ***.... Adapted from Theodore Levitt***

WELCOME

To Employee Orientation Workshop for PGE's Customer Focus Initiative.

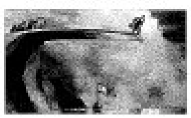
Upon regaining ownership independence in 2006, PGE officers renewed our Statement of Direction. They identified Customer Satisfaction as a key fundamental to take to the next level of excellence.

A Management team developed an initiative-plan for moving forward.

This workshop is the first level or step of your participation in the Customer Focus Initiative.

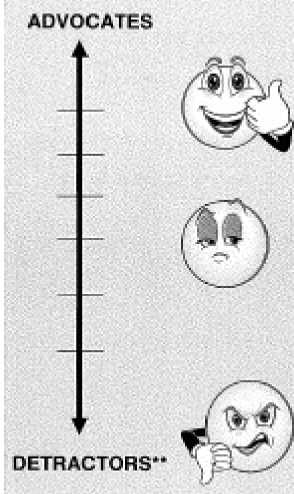
Level 1: ORIENTATION	Attend orientation. This workshop will help you "Recast" your work.
Level 2: UNIT ACTION	Go beyond Orientation to quick action improvements. This workshop will set you up to do so.
Level 3: UNIT INITIATIVE	Go beyond Orientation to more ambitious improvements. This workshop will set you up to do so.

Lets dive in



… with a warm-up exercise. We will introduce ourselves and say more about the agenda after that.

ADVOCATES and DETRACTORS
DEFINTION OF TERMS



ADVOCATES -
great experiences/stories

Have experiences with a company that exceed their expectations, they are loyal; they tout the organization

APATHETICS –
good experiences/stories

Are merely satisfied; basic expectations are met; they would consider switching to another provider when possible; they have no comment about the organization

DETRACTORS* -
bad experiences/stories

Have experiences with a company in which their basic expectations are not met. They seek out competitor-providers. They "bad-mouth"* the organization.

* Research shows that Detractors more firmly hold their opinions (are "stickier") and are 50% more likely to talk about their bad experiences than are Advocates to talk about their great experiences.
** J.D. Powers refers to "detractors" as "assassins"

ADVOCATE AND DETRACTOR STORIES

your experiences as a customer

ADVOCATE STORIES. Share a recent experience in which an organization performed so well for you that you were moved to tell others how great it was.

DETRACTOR STORIES. Share a recent experience in which an organization performed so poorly for you that you were moved to tell others how terrible it was.

YOUR REACTIONS? what did you feel? do? feel like doing?

WHAT GENERALIZATIONS? what are distinguishing characteristics of Advocate Stories and Detractor Stories?

SHOULD THEY? WHY?

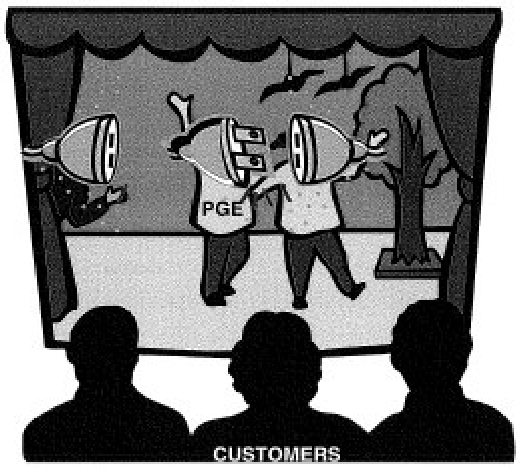
What would be the benefits to those organizations if they created more advocates and less detractors?

CUB/211
Jenks/6

WE CREATE STORIES TOO

Let's switch perspectives from us as customers to us as producers.

POWER SHOW



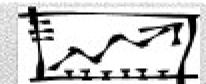
**WE PRODUCE STORIES.
WE PERFORM FOR OUR CUSTOMERS**

THE CUSTOMER FOCUS INITIATIVE

LET'S GO good to great ON CUSTOMER SATISFACTION

Goals

Let's achieve gains in Customer satisfaction

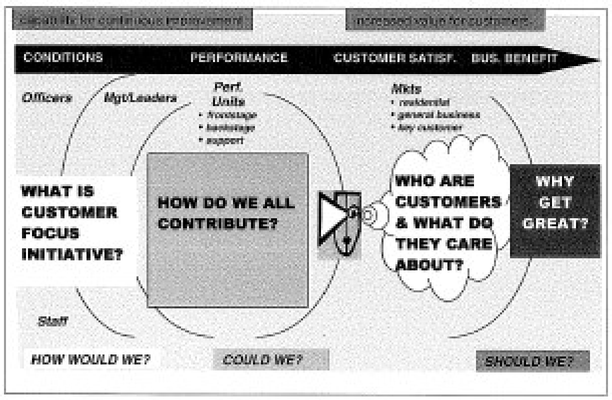


Let's build our capability To continuously improve Customer satisfaction

Initiative is not about.	***Rather ....***
CORRECTING DEFICIENCY	***THIS BUILDS ON STRENGTH***
JUST RAISING SURVEY SCORES	***IT IS ABOUT CULTURE*** ***Our beliefs and habits***
PRESCRIBING SOLUTIONS	***IT IS ABOUT BUILDING CAPABILITY***
JUST ONE YEAR	***IT'S A MULTI-YEAR PURSUIT***
PERSUADING US TO CARE	***WE ALREADY CARE*** *This goes with the grain of why people want to work at PGE*
JUST CUSTOMER FACING EMPLOYEES	***WE ALL HAVE A ROLE*** *We all impact paying customers*

WORKSHOP OBJECTIVES & AGENDA

1. **WHY GET GREAT?**
   ADVOCATES & DETRACTORS
   -- know more about why --
2. **WHO ARE CUSTOMERS? WHAT DOTHEY CARE ABOUT?**
   VOICE OF THE CUSTOMER
   -- know more about customers --
3. **HOW DO WE ALL CONTRIBUTE?**
   LINE OF SIGHT.
   -- know more about your role --
4. **WHAT IS THE CUSTOMER INITIATIVE?**
   -- know more about the initiative --



COMMON, SENSIBLE DOUBTS

Reservations and Misgivings about Going Good to Great

SHOULD WE?

- What is the hurry? Why now?
- What difference would it make? Customers have no choice.

COULD WE?

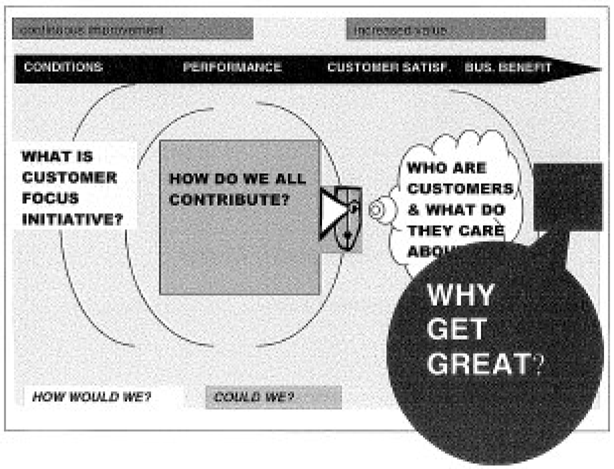
- Aren't we already great?
- Aren't we already doing all we can with the resources we have?

HOW WOULD WE?

- Won't this just be "flavor of the month"?

BACK TO US:

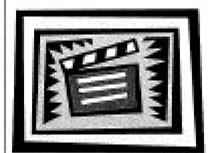
1. WHY SHOULD PGE GET GREATER AT CUSTOMER SATISFACTION?



PGE ADVOCATES AND DETRACTORS

We too produce bad, good and great experiences

STORIES. Recall stories you played a part in or know about that were so bad or so great that PGE customers would have understandably been moved to tell others.



Video:
VOICE OF PGE'S CUSTOMERS

APPLY THE SAME DEBRIEF QUESTIONS TO OUR REGULATED BUSINESS

PGE CUSTOMER REACTIONS? Do PGE customers have reactions? feelings? do's? want-to-do's?

____
____
____
____

WHAT GENERALIZATIONS? What are distinguishing characteristics of PGE Advocate and Detractor stories?

____
____
____
____

SHOULD WE? WHY?

What would be the benefits to PGE if we created more advocates and less detractors?

____

____

____

____

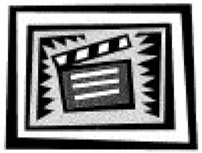
____

____

____

Compare to previous "should-they" list.

OFFICER VIDEO



Why Now?
What Business Benefit?

NOW IS THE TIME

Looking back
We have withstood and emerged from adversity ...

- We have regained independence
- We have opportunity to be more proactive
- Let's justify the loyalty of our advocates
  And re-earn the support of our detractors
- Let's prove no one can operate this place better

Looking ahead
We face 21st century challenges:

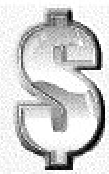
- Customer expectations are rising.
  Power costs are rising.
  We need to protect & enhance our value proposition
- Trust will become more crucial
- Our investors care
- Time to unify us, enthuse us, expand our capability

BUSINESS BENEFIT

POLITICAL SUPPORT

- Gain proponents and good-will in regulatory and political settings

PROFIT/PREMIUM

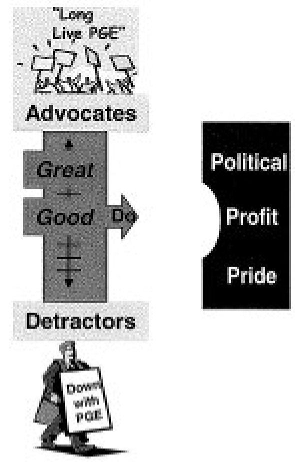


- Reduce cost of poor quality & complaints
- More favorable Regulatory Treatment
- Customers' choices to do business with us, revenue
- Increased Investor Confidence in Our Future Earnings

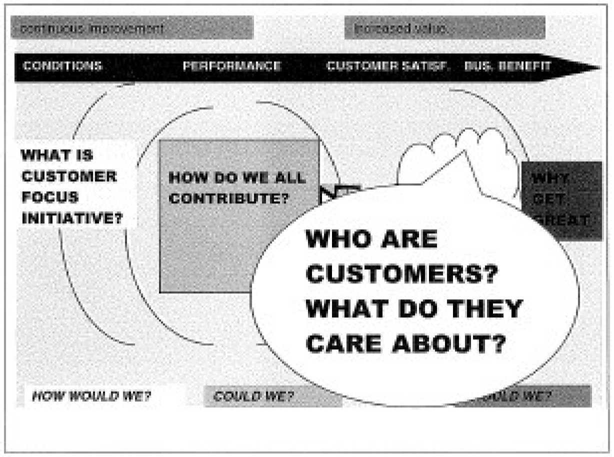
PRIDE

- Employees gain sense of achievement, contribution, and get positive feedback from customers.
- Helps attract and retain people.

WHY SHOULD PGE GET GREATER AT CUSTOMER SATISFACTION?



2. VOICE OF THE CUSTOMER

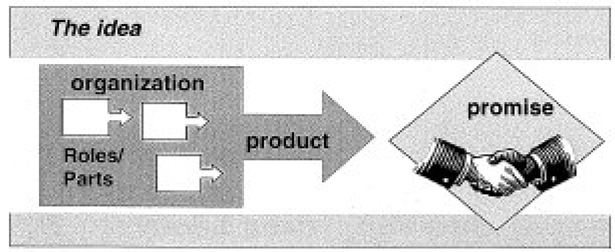


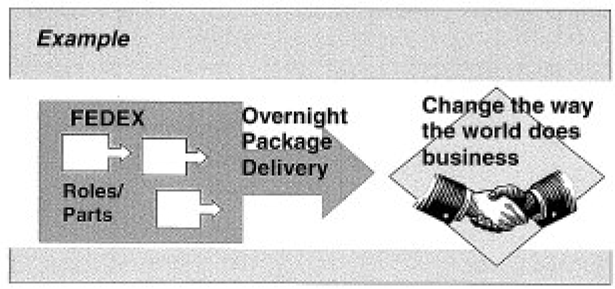
We Are Story-Makers

Great story-makers know their audience, their customers.

HOW DO CO.'S CONTRIBUTE TO CUSTOMER'S LIVES?

What is their **Promise** to their customers?
What larger purpose is everyone's work in service to?

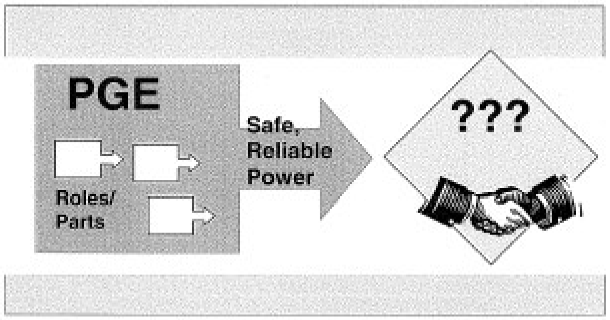




CUB/211
Jenks/12

HOW DO WE CONTRIBUTE TO CUSTOMER'S LIVES?

What is our **Promise** to our customers?
What larger purpose are all our jobs & stories in service to?



Worksheet # 1 RESIDENTIAL MARKET

MARKET SIZE?	WHO ARE THEY?	WHAT'S IMPORTANT TO THEM?	HOW SATISFIED ARE THEY? (Net Advocacy)
Guess %	Name 3	Rank the Factors	Guess %
of 713,000 # ____ % of customers of $1.4 billion $ ____ % of PGE revenue for Dec.'06	____ ____ ____	Mark "1" for most important? "4" for least important Reliability ___ Service ___ Price ___ Reputation ___ for Dec.'06	10 9 8 7 6 5 4 3 2 1 0 ____% 8-10's ____% 0-5's for Dec.'06

Worksheet # 2 KEY CUSTOMERS

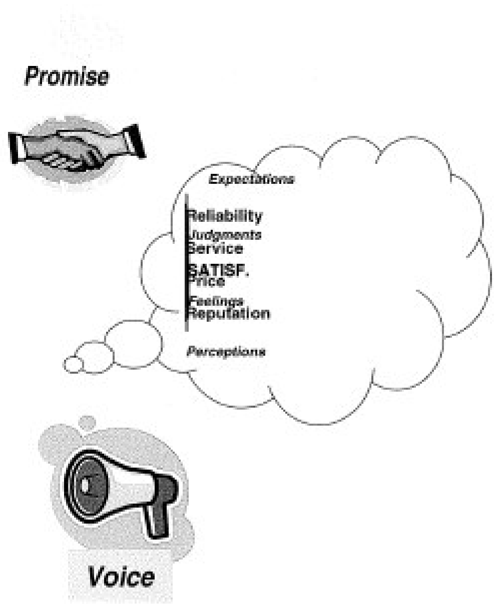
MARKET SIZE?	WHO ARE THEY?	WHAT'S IMPORTANT TO THEM?	HOW SATISFIED ARE THEY? (Net Advocacy)
Guess %	Name 3	Rank the Factors	Guess %
of 713,000 # ___ % of customers of $1.4 billion $ ___ % of PGE revenue for Dec.'06	______ ______ ______	Mark "1" for most important? "4" for least important Reliability ___ Service ___ Price ___ Reputation ___ for Dec.'06	10 9 8 7 6 5 4 3 2 1 0 ___% 8-10's ___% 0-6's for Dec.'06

Worksheet # 3 GENERAL BUSINESS CUSTOMERS

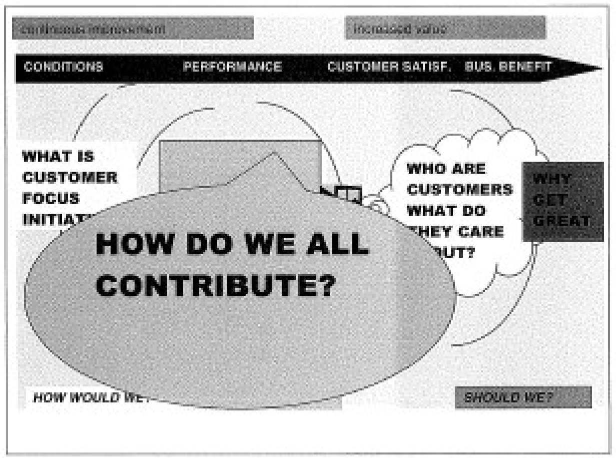
MARKET SIZE?	WHO ARE THEY?	WHAT'S IMPORTANT TO THEM?	HOW SATISFIED ARE THEY? (Net Advocacy)
Guess %	Name 3	Rank the Factors	Guess %
of 713,000 # ___ % of customers of $1.4 billion $ ___ % of PGE revenue for Dec.'06	______ ______ ______	Mark "1" for most important? "4" for least important Reliability ___ Service ___ Price ___ Reputation ___ for Dec.'06	10 9 8 7 6 5 4 3 2 1 0 ___% 8-10's ___% 0-6's for Dec.'06

VOICE OF THE CUSTOMER

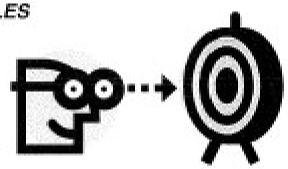
WHO ARE CUSTOMERS?
WHAT DO THEY CARE ABOUT?



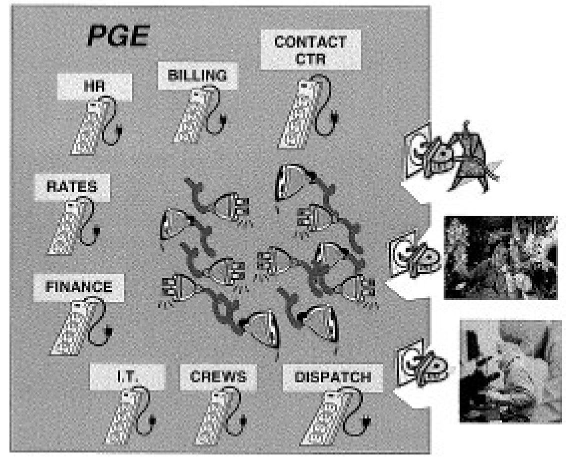
3. LINE OF SIGHT



WE ALL HAVE ROLES IN CREATING CUSTOMER STORIES



LET'S GET CONNECTED -- EXERCISE

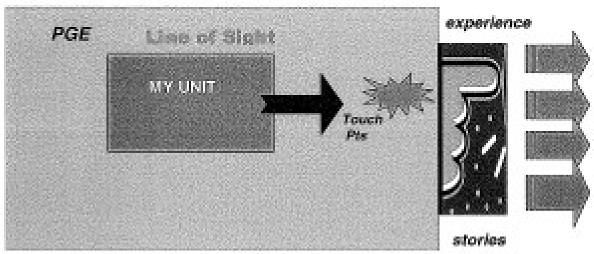


- You all are assigned roles = power strips
- You all make connections = power cords to customers and coworkers
- Let's learn how to map Line of Sight.

CUB/211
Jenks/16

TOUCH POINTS

Your connections to customers



Frontstage work makes **direct impacts on Customers**, through Reliability, Service, Price or Reputation

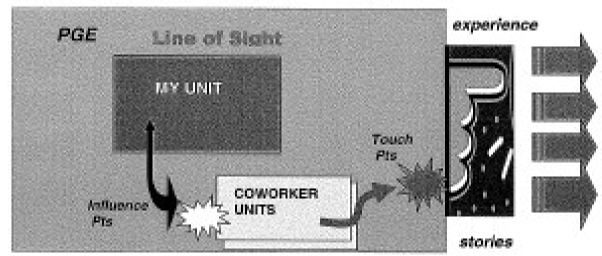
Touch Point = Any moment that a customer interacts with or observes PGE that then contributes to their judgment or feeling about PGE

Examples *(human interaction, system interaction, observation)*

Use Power	Receive Bill
Enroll in Special Program	Go to Website
Report an Outage	See PGE Crew at Work
Call to Move Residence	See Person Wearing PGE Logo
New Connection	Talk to Neighbor about PGE
Create event covered in media	Advertisement

INFLUENCE POINTS

Your connections to coworkers



Backstage is operational or staff work that makes direct impact on coworkers which then indirectly leads to impact on customers

Influence Point = Work impacts help or hinder PGE coworkers' performance (eg. inputs, or working conditions that direct, enable and motivate others)

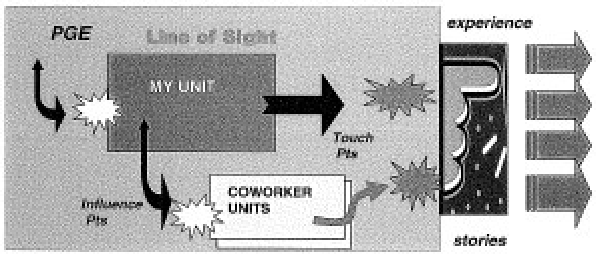
Examples

Put Outage OT in Paycheck	Provide Customer Survey info.
Negotiate/Set Tariff Rules	Provide desktop technology
Legal Advice @ Cus. Claim	Maintain trucks
Set Capital Budget for Mtnce	Operate plants efficiently

CUB/211
Jenks/17

TOTAL LINE OF SIGHT: CONNECTION POINTS

You have been delegated a piece of the business (unit or job).
You have a part to play in our story making.



Your Connection Points are a combination of:

Touch Points. You have opportunities to directly impact customer experience of reliability, service, price and reputation.

Influence Points. You have opportunities to indirectly impact customers through impacts on coworker units. You help or hinder their downstream performance.

Take note:

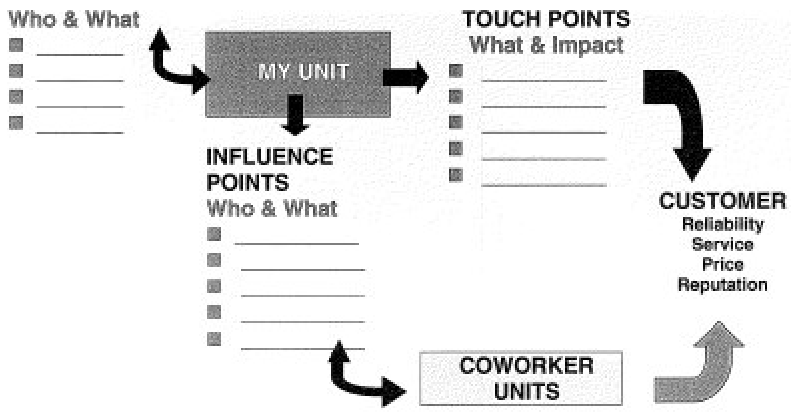
Coworkers Influence You too. You are the receiver of influence. Others help or hinder your performance for customers.

Upstream Influence, Influence can go both ways. You can help upstream coworkers understand and give you what you need to perform,

Be Accountable to the "whole", to making all the connections work, to both giving and getting what is needed in order to perform for the end customer.

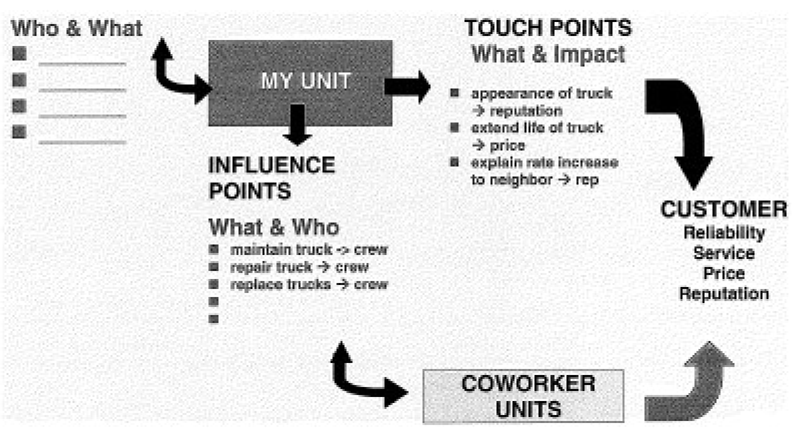
TRY LINE OF SIGHT MAPPING for Assigned PGE Role

- Describe your work as primarily frontstage or backstage (operating or support)
- What direct Touch Points do you have? Impacts on customers view of reliability, service, price or reputation?
- What Influence Points do you have, impacts on coworkers? Who are they?
- What coworkers do you depend on in order to perform



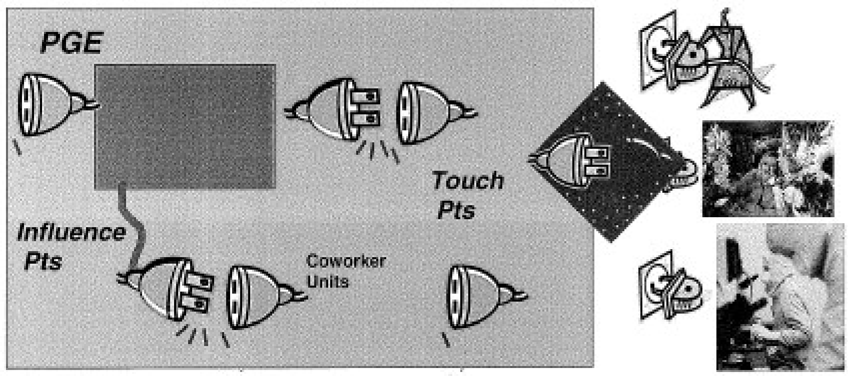
EXAMPLE LINE OF SIGHT MAPPING for Fleet

- Describe your work as primarily frontstage or backstage (operating or support)
- What direct Touch Points do you have? Impacts on customers view of reliability, service, price or reputation?
- What Influence Points do you have, impacts on coworkers? Who are they?
- What coworkers do you depend on in order to perform



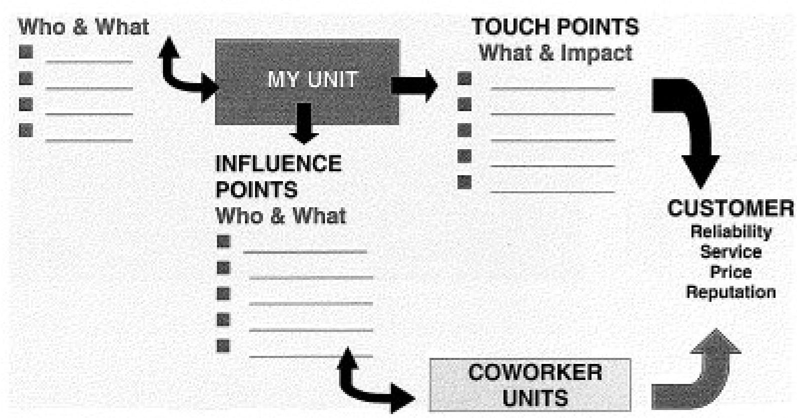
CUB/211
Jenks/19

CONNECT UP



TRY LINE OF SIGHT MAPPING for Your Real Work

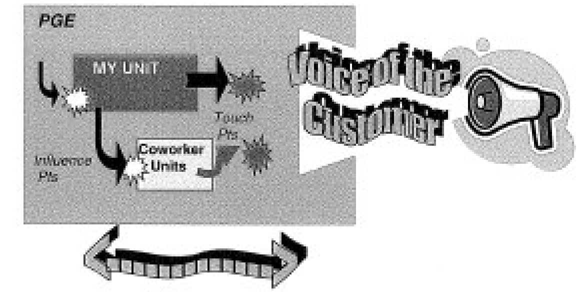
- Describe your work as primarily frontstage or backstage (operating or support)
- What direct Touch Points do you have? Impacts on customers view of reliability, service, price or reputation?
- What Influence Points do you have, impacts on coworkers? Who are they?
- What coworkers do you depend on in order to perform



CUSTOMER FOCUSED CONNECTIONS

Focus & align connection points to the voice of the customer

Great Stories are made of great connection points, touch points and influence points.



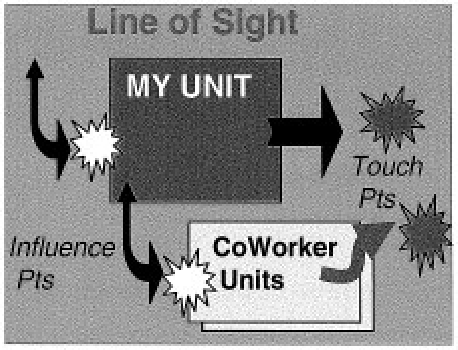
WHY DO WE DO IT THE WAY WE DO?

Connection points are great when they are attuned to the Voice of the Customer, when we think outside-in about what we do.

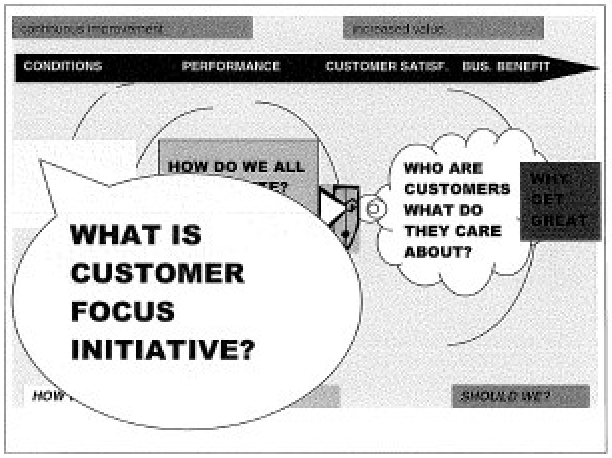
> **Inside-Out**. When we do what we do to meet our own needs (self-serving), we risk producing bad stories.
>
> **Outside-In**, When we do what we do to meet customer needs (in service to them) we increase chances of producing great stories.

LINE OF SIGHT

How do we all contribute?



WHAT'S THE CUSTOMER FOCUS INITIATIVE?



CUSTOMER FOCUS INITIATIVE

2007 Goals	Principles
Build Understanding and Commitment	*Different Actions by Different Areas*
Connect to Employees Work	*No Shame, No Blame.*
Get Early Wins, Get Action	*Slow is Fastest*
	Set Sights on Ultimate Customers Internal clients are means to that end

Supporting Actions
FOR MANAGEMENT & STAFF

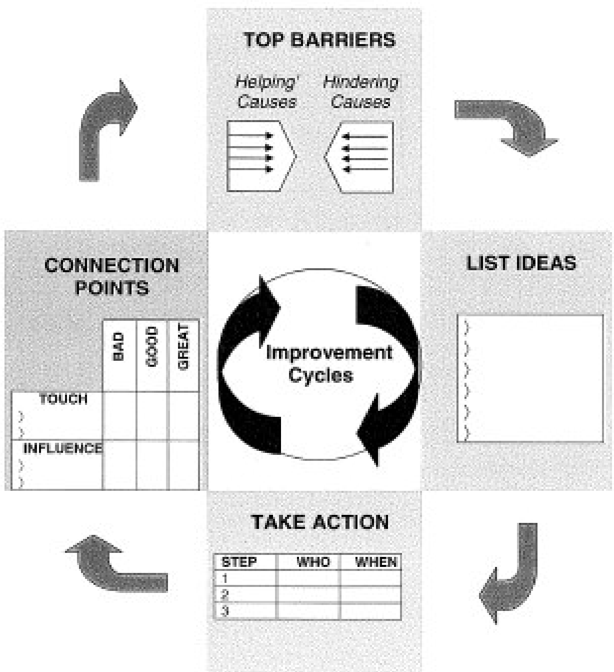
Management Sponsorship
eg. call to action, reinforce, coordinate, remove barriers

Staff Services
eg. measurement, training selection, recognition

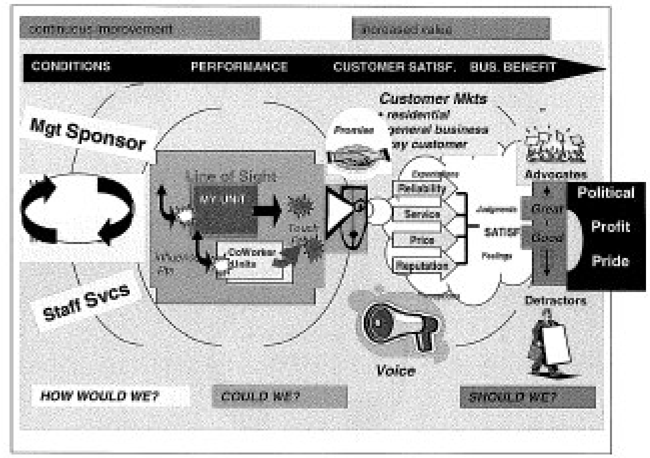
Participation Levels –
FOR WORK GROUPS

1. **Orientation**
   -- recast line of sight
2. **Unit Action**
   -- do line of sight and an improvement cycle
3. **Unit Initiative**
   -- do more ambitious assessment and improvement

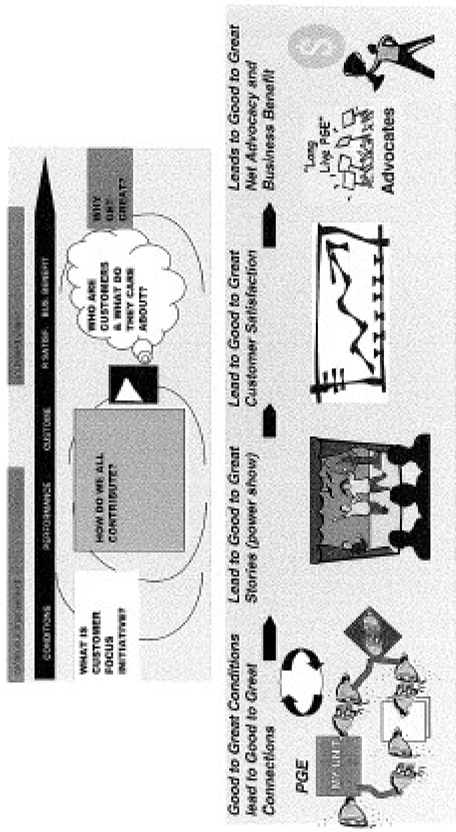
IMPROVEMENT CYCLES



CUSTOMER FOCUS INITIATIVE



WORKSHOP REVIEW



Good to Great Conditions lead to Good to Great Connections

PGE

Lead to Good to Great Stories (power show)

Lead to Good to Great Customer Satisfaction

Lends to Good to Great Net Advocacy and Business Benefit

Advocates

Focus your Line of Sight.
Align your Connection Points to the Voice of the Customer
Help create great stories and greater Net Advocacy

YOUR CLOSING THOUGHTS

WHAT DID YOU GAIN TODAY?
.... New Insights
.... Questions to think about
.... Ideas for action

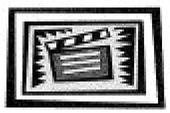
____

____

____

CUB/211
Jenks/24

CALL TO ACTION



What a Feeling!

"it feels great to achieve great"

LETS GO GOOD TO GREAT ON CUSTOMER SATISFACTION

- **LET'S DELIVER ON OUR PROMISE AT EVERY CUSTOMER TOUCH POINT.**
- **NOW IS THE TIME**
- **THERE IS SIGNIFICANT PAYOFF IF WE DO IMPROVE** (ie. advocacy, profit, pride)
- **THERE IS SURPRISING ROOM TO IMPROVE** (eg. intentional conditions)
- **WE ARE ACHIEVING GOOD AND WE ARE NOT EVEN CLOSE TO PEAKING. JUST IMAGINE!**

Let's, every division, group and individual in the organization, step up to the challenge to add greater value to customers. Let's distinguish ourselves through great quality and service and to containing price.

Find your **path of contribution** (line of sight), **get the voice of the customer on your scorecard,** and find ways to excel on your path, use **focus, alignment and ingenuity** to provide more value with your resources.

GLOSSARY

Advocate	A customer so impressed with PGE that he/she tells others how great we are.
Backstage	PGE units, jobs, and work-tasks that are part of operations and production but do not directly touch customers (behind the scenes). Backstage typically create inputs for frontstage work.
Business Benefit	The impacts on other stakeholders (eg. investors, employees) that follow from how we perform for customers, eg. profit, pride
Conditions	Attributes of the work environment that direct, enable and motivate performance (eg. expectations, feedback, reward, rules, communication, training, selection, processes, tools ....)
Connection Points	All influences and touches on the path from all employees to ultimate customers. Touch points and influences points are two kinds of connections.
Customer Promise	The greater contribution that PGE makes to customers' lives. The inspirational purpose that every employee's work is in service to.
Detractor	A customer so negative about PGE that he/she tells others how poor we are.
Frontstage	PGE units, jobs, and work-tasks that directly touch customers.
Influence Point	Any and all impacts inside PGE that in turn affect touch-points. These could be practices, rules, treatments, inputs, working conditions or more that help or hinder PGE performers.
Line Of Sight	The path of contributing impacts from each role in PGE to ultimate customer satisfaction.
Net Advocate	The number of advocates minus the number of detractors to arrive at a measure that approximates good will or loyalty
Outside-In	Refers to reasons we do things the way we do. To the extent we do things based on the voice of the customer, we are "outside-in". To the extent we do things to meet our own needs, we are "inside-out".
Price	The cost of electricity
Reliability	The consistency and quality of the flow of kwh we provide ie. our product quality
Reputation	Customers opinion about how well run our company is (how well managed, operated) and about our corporate citizenship
Satisfaction	The judgments and feelings customers form about their experience of doing business with PGE
Service	The positive-ness of interacting with PGE people and systems, eg. the ease, the pleasantness, the competence
Support	PGE units, jobs, and work-tasks that are staff functions that do not directly touch customers (behind the scenes). Support work typically affects conditions in which both front & backstage work.
Touch Point	Direct impacts on customers. Any moment that any customer (through interaction or observation) that feeds into their overall judgment or feeling about PGE (from direct home visit or phone contact to seeing an employee with a PGE logo shirt at the mall).
Voice Of Customer	An expression of customers' point of view, their expectations, needs, preferences and reactions. Ways to tune into the voice of the customer include, asking, observing, surveying .....

September 10, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE *Supplemental* **Response to CUB Data Request**
Dated July 1, 2008
Question No. 097

Request:

The CRG Summary provided in response to CUB data request 50 Attachment A is dated Wednesday, May 21, 2008.

a. **Is this the version of the Project Summary/Approval upon which the decision to purchase the helicopter was made?**
b. **Please provide a copy of the CRG Summary that was signed for approval.**

Response:

a.) Yes.

b.) Attachment 097-A is a copy of the project summary that was signed for approval. Note that the date of May 21, 2008 from Attachment A of CUB data request 050 reflects an automatic update of the date in Word when the document was resaved for purposes of responding to a data request, and not a revision date of the Project Summary. The document in Attachment 097-A and the document in Attachment 050-A are the same, except Attachment 097-A provides a signed copy.

Supplemental Response (Sept 10, 2008):

PGE has recently received verbal notice that the helicopter will not be delivered until late 2009. Given the new helicopter will require some assembly and outfitting prior to use, it is not expected to be ready for operation until 2010. This change also means that PGE would use its old helicopter throughout 2009, not just in the first half. PGE expects to make this modification to its test year revenue requirements in its Sursur rebuttal testimony.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 113

Request:

PGE experienced "significantly lower" use of its helicopter in 2006 and 2007 due to an aging helicopter, pilot illness, and difficulty in contracting experienced pilots.

a. During 2006 and 2007 did PGE use other means to conduct the inspections that would have done with the helicopter or did it not inspect some parts of its transmission lines.
b. Did shifting transmission inspections to other means cause any costs to be incurred. If so, please list any incremental costs associated with shifting inspections from the helicopter to other means.
c. Did the Company incur any overtime because it had to shift some inspections from the helicopter to other means.

Response:

a. No. PGE did not supplement inspections by helicopter with other means during 2006 and 2007 because we have some flexibility with inspecting transmission lines. At times, we are able to defer inspections. In 2008, helicopter inspections have been completed as scheduled.

b. No.

c. No.

September 5, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 117

Request:

PGE/1900/11-13. For each R&D project listed in this section please provide the following:

a. **The analysis (not a summary of the analysis) that led PGE to believe funding it was appropriate.**
b. **An explanation of how customers benefit from this expenditure.**
c. **An explanation of why funding this project is appropriate for an electric utility.**
d. **An explanation of why PGE believes the project should be considered "used and useful."**

Response:

PGE Research and Development (R&D) is overseen by PGE senior management, managers, and supervisors. R&D Committee operations, funding projects, project selection and status reports are reviewed on a monthly basis. Each fall the annual corporate R&D cycle begins with a call to all areas of the company (Every area in the company is eligible to participate). Project sponsors submit written research proposals to the R&D Committee.

R&D proposal requirements include a written request with identification of the project lead and collaborator, description of the project including other entities involved in the collaboration, identification of the benefit to PGE and risks of non-participation, alternative approaches, identification of total annual costs and expected duration. All proposals include amounts the sponsoring area (responsibility center or RC) can or will contribute to the project.

All targets and projects that receive R&D funding are reviewed by the R&D Committee. All projects must be approved each year and the previous year's projects must be resubmitted for renewal consideration. All proposed projects are ranked by project value, qualitative and/or quantitative, and funds distributed accordingly.

Members of PGE's R&D Committee independently review R&D proposals that will benefit and bring increased value to the customers, including increased economic value at PGE power plants; successful and cost-effective relicensing or decommissioning at hydro facilities; distributed generation; product development in response to or anticipation of deregulation (market-based programming, green power, cost of service, system benefit charge effects, industrial and commercial customers, etc.) However, PGE's R&D Director and Managers analyze various areas of research and scrutinize issues that affect PGE customers.

PGE's Response to OPUC Data Request No. 269, Attachment B-2 provided proposed areas of research since the above process has not been conducted for 2009.

For additional information see PGE Exhibit 500, Pages 7-11, and PGE Exhibit 1900, Pages 10-13 as well as PGE's Responses to OPUC Data Requests No. 269, 279, and 290, and CUB Data Request No. 37.

See Attachments 117-A through 117-E for a detailed explanation of the five potential areas of research listed in PGE Exhibit 1900, pages 11 through 13. These proposed areas of research cover long-term issues important to PGE and its customers.

For subject areas, we provide analyses as to why PGE believes funding should continue and be appropriate, provide an explanation of how customers will benefit from the continued expenditures, why funding of projects for the area should continue to be appropriate for an electric utility and whether PGE believes the areas of research and final projects should be considered "used and useful."

Attachment 117-E1 is Confidential, Proprietary and Subject to Protective Order No. 08-133.

Research Area	Sub-Total Cost	Total Cost at 100% ($)	Impact of 25% funding
Distributed Energy Storage			
Plug-in Electric Hybrid Vehicles			
• Plug-in Electric Vehicle Initiative – Charging Station Pilot Project	10,000		10,000
• Conversion of two hybrids w/ advanced battery	75,000		50,000
• New EV with advanced battery	75,000		40,000
• Joint Partnership w/ manufacturer	100,000		0
Sub-total	250,000	250,000	**100,000**

20% of $500,000

a. The analysis (not a summary of the analysis) that led PGE to believe funding it was appropriate

Attachment 117-B1 is a detailed research offering from EPRI covering the demonstration needs surrounding compressed air energy storage (CAES). PGE believes this a good example of the increasing awareness of the role distributed energy storage will have in (1) helping level peak power requirements; (2) providing minimum power "bridging" that would otherwise require turning on a large and expensive peaker power plant and (3) compensating for the intermittency of renewable power technologies such as wind and solar.

b. An explanation of how customers benefit from this expenditure

Customers benefit from this research in the following manner:

- On their behalf, PGE assesses the viability, timeliness and cost-effectiveness of CAES technology as a form of distributed energy storage;
- Should PGE support this specific EPRI demonstration, the company would evaluate its potential for the Biglow Canyon wind power plant which would be in the range of power (20 to hundreds of MW) where this technology would have application;
- The technology would be added to PGE's capability in helping "flatten" peak power demand. Although this example concerns CAES technology, the same arguments and cost / benefits would apply to any opportunity to store energy on a distributed model (e.g., via advanced, deep cycle lithium ion batteries in plug-in hybrid electric vehicles.)

c. An explanation of why funding this project is appropriate for an electric utility

PGE believes it is incumbent on any electric utility to seriously consider reasonable and cost-effective opportunities to manage peak power requirements to yield both system reliability and economic benefit to customers. This would be especially true should the same technology also have applicability in helping offset or compensate for the intermittency of wind and solar over short (several hours) time periods. The ability to store energy to offset either marginal power purchases (e.g., should a wind plant not deliver forecasted power) or to help shave power peaking would in each instance, offset the most expensive power that PGE would normally acquire. Naturally, the ability to store energy would contribute to system stability and reliability – the benefits of which are quite high.

d. An explanation of why PGE believes the project should be considered "used and useful"

These projects represent prudent operations and maintenance expenditures. These projects represent prudent operations and maintenance expenditures, are not capital jobs, and thus "used and useful" does not apply.

The fill-up's free in Portland, if you've got a plug-in hybrid car

Electric hybrids - PGE unveils an outlet, plans more around Portland to push charge-up vehicles
Wednesday, July 30, 2008
DYLAN RIVERA
The Oregonian Staff

What price is low enough to entice droves of Oregonians to fill up their cars with electricity generated by Northwest wind turbines rather than gasoline made from imported fossil fuels?

How about free -- from drive-up stations across the metro area?

That's the strategy Portland General Electric Co. launched Tuesday when it unveiled the first of a dozen plug-in vehicle-charging stations it will install through September. The utility hopes the stations -- a bit taller than Portland's electronic parking meters, with a sleek blue and silver design -- will encourage ownership of plug-in electric vehicles by offering visibility, convenience -- and a hard-to-beat price. The free test period will continue for an undetermined time.

"It's what we want to call the filling station of the future," said Bill Nicholson, vice president of customers and economic development for PGE.

PGE and several major automakers are gearing up for what they consider the next generation of cars: gas-electric hybrids with plug-ins to use electricity to reduce gas consumption and greenhouse gas emissions. They think Portland, which has the nation's highest ownership rate for the standard Toyota Prius hybrid, could be at the vanguard.

"Wouldn't it be great to charge up your battery while you're shopping or visiting OMSI, so the gas motor barely has to fire up?" Nicholson said. "That's the concept with this next-generation car."

But why go for a plug-in hybrid when 100 percent electric cars have been around for more than a decade? Because, industry observers say, such cars so far suffer from federal speed limits of 25 mph, high prices and technology glitches.

Gas-electric hybrids such as the Prius have caught on nationwide, offering performance and reliability comparable to that of standard gas-powered passenger cars. Fuel economy of up to 60 miles per gallon has drawn flocks of consumers, especially amid rising gasoline prices.

Only 268 all-electric passenger cars are registered in Oregon, state transportation officials say. But the state has 26,338 registered hybrids -- still shy of 1 percent of the state's 3.3 million passenger cars.

Advocates of plug-in technology say a hybrid with a plug could be better than a standard hybrid. The plug-in cars could get better mileage -- perhaps 100 miles or more a gallon. Consumers also may like knowing they can recharge with any standard 110-volt household electrical outlet and still have gas as backup power.

"When you're all-electric, you're very reliant on how far your car can go," said Elizabeth Paul, project manager for PGE.

That makes the availability of electricity on the road a crucial consideration, Paul added.

PGE unveiled the first in its new fleet of charging stations Tuesday at its headquarters downtown. The company has offered a nondescript electrical outlet there since 1996; the new station comes with an 8-foot-tall stainless-steel design that will be replicated across the area. Shorepower Technologies, a startup with West Coast operations based in Portland, built the stations.

The stations cost about $2,000 each, and companies that host stations pay for equipment, any underground utility extensions -- and the power bill for car users. Charging up a test Toyota model takes about three hours with a 110-volt outlet and uses as much electricity as running a large microwave for three hours. The stations offer 220-volt plugs that charge faster.

PGE passes all costs on to the stations' host companies and buys renewable energy credits so that the stations sell power generated from wind, solar or hydroelectric sources, not coal. Even under those terms, local business interest in the project has been "overwhelming," said PGE's Nicholson, as companies look for a visible way to show a green ethic.

In coming years, PGE envisions charging electric cars, and potentially giving users discounts for those who charge during off-peak hours.

PGE touted its plans by presenting a test model of a plug-in hybrid Toyota Prius, one of only five in the nation.

In 2010, Toyota plans to sell a demonstration plug-in Prius to commercial fleets, said Chris Hostetter, group vice president with Toyota Motor Sales U.S.A. Inc. Using a lithium-ion battery, the model could travel up to 10 miles at speeds up to 60 mph, all while using no gasoline.

With battery packs costing about $500 per mile of travel capacity, a 10-mile range could add about $5,000 to the cost of a Prius, Hostetter said.

"That's what we're researching now: How many miles do people really drive all electric?" he said. "How much convenience do they want? Do they want to go more miles with less trunk space but pay more?"

Dylan Rivera: 503-221-8532; dylanrivera@news.oregonian.com For environment news, go to: oregonlive.com/environment

Project	Job #	Job Title	Rank	Year	Notes
P21633	23650	Sand Springs Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	23651	Sycan Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	23652	Fort Rock Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24881	Beaver Plant Switchyard - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24883	Coyote Springs Switchyard - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24886	Fairmont Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24887	Faraday Plant Switchyard - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24888	Grand Ronde Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24890	Indian Substation - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24891	Pelton Switchyard - Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24892	Port Westward Switchyard- Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24894	St Helens Substation Enhance Security NERC (Catg 5)	1,1	2009	
P21633	24896	Physical Security Upgrade at Bald Peak Telecom Site	1,1	2009	
P21633	24897	Physical Security Upgrade at W. Salem Telecom Site (2009)	1,1	2009	
P25696	25696	Pelton - Install automated fish ladder cell cleaning system	1,1	2009	
P16567	16567	T&D System Inspection, Major Maintenance-UG	1,2	2009	
P17443	17443	T&D System Inspection, Pole Treatment/Replacement	1,2	2009	
P22564	22564	Separate St Marys-Trojan 230kV & Keeler-St Marys 230kV Db	1,2	2009	
P24723	25383	Arc Flash - Core Area	1,2	2009	
P24723	25531	Arc Flash Mitigation - Canyon substation	1,2	2009	
P24723	25532	Arc Flash Mitigation - Mill Creek substation	1,2	2009	
P24723	25533	Arc Flash Mitigation - Cedar Hills substation	1,2	2009	
P24723	25534	Arc Flash Mitigation - Grand Ronde substation	1,2	2009	
P25410	25410	Town Center Substation - Install Oil Spill Containment	1,2	2009	
P25410	25411	Harborton 115kV Substation - Install Oil Spill Containment	1,2	2009	
P25410	25412	Dilley Substation - Install Oil Spill Containment	1,2	2009	
P25605	25605	C Springs 1-Upgrade GSU Transf Oil Spill Prevention	1,2	2009	
P14757	14757	Underground Locating	2,1	2009	
P15760	15760	Colstrip- Plant Additions	2,1	2009	
P15760	21629	Colstrip - Ongoing Transmission Upgrades	2,1	2009	
P20594	20594	Sunset substation - Install WR8 50 MVA Transformer	2,1	2009	
P20594	25485	Sunset substation - Install Oil Spill Containment for WR8	2,1	2009	
P20594	25486	Intel dist. feeders (radial) - Replace padmount switches	2,1	2009	
P20594	25522	Sunset substation - Relocate D1B3 Feeder from WR5 to WR7	2,1	2009	
P24303	24303	Scholls Fry New Sub - Purchase Property W of Murrayhill	2,1	2009	
P25056	25099	Purchase New Temporary Substation	2,1	2009	
PB2000	B2000	Blanket-Distribution Lines-Non Customer	2,1	2009	
PB2000	B2500	Blanket-Non Customer Street Widening	2,1	2009	
PB4000	B4000	Blanket-Distribution Lines-New Customers	2,1	2009	
PB4000	B4500	New Customers-Connect Streetlights	2,1	2009	
PB4000	E3684	Purchase Utilization Transformers-New Customers	2,1	2009	
PB4000	E3700	Purchase Electric Meters	2,1	2009	
PB4000	KC475	UNITY	2,1	2009	
P20512	20512	Habitat MOU	2,2	2009	
P23331	23986	2009 QRP Reliability Improvements	2,2	2009	
P23556	23581	Canyon Sub - Install PQ Metering	2,2	2009	
P23659	23659	Install Atmospheric Data Equipment - Carty Meterological Twr	2,2	2009	
P24182	25631	Enterprise Protection for Sensitive Data	2,2	2009	
P24330	24928	PGE Web - .BIZ Site Upgrade	2,2	2009	
P24330	24929	PGE Web - Implement Web Analytics Tool	2,2	2009	
P24330	25457	PGE Web - Functional Enhancements and Improvements	2,2	2009	
P25538	25538	Purchase Vehicles for Discontinuation of Employee Vehicle Ov	2,3	2009	
P14628	14628	Replace Failed Underground Cables	3,1	2009	
P23260	23260	Boardman-Miscellaneous Pumps, Valves, Motors, etc.	3,1	2009	
P23260	23626	Beaver-Miscellaneous Pumps, Valves, Motors, etc.	3,1	2009	
P23260	23628	Coyote Springs 1-Miscellaneous Pumps, Valves, Motors, etc.	3,1	2009	
P23260	23661	Port Westward-Miscellaneous Pumps, Valves, Motors, etc.	3,1	2009	
P19032	19032	Substation Fitness Program	3,2	2009	
P19349	19932	Distribution Automation of Canyon #3 Network	3,2	2009	
P19712	20381	Underperforming Feeder Improvement for 2001 to 2012	3,2	2009	
P20657	21577	Beaver-Replace CT Excitation System Unit #2	3,2	2009	
P21616	21616	Bdmn-Install New Coal Dust Suppression System	3,2	2009	
P21633	25227	Harborton Substation Expanded Metal Fencing - 12500 NW Ma	3,2	2009	
P21633	25229	McLoughlin Substation Expanded Metal Fencing	3,2	2009	
P21633	25633	Westside Hydro Faraday - Enhance Security	3,2	2009	
P22063	22063	Communications Site Upgrade	3,2	2009	
P22074	22074	Network Comm. UPS & DC Distribution Vintage	3,2	2009	
P22074	24739	TCC UPS and Battery Vintage	3,2	2009	
P22074	25470	Replace TCC DC Rectifier System	3,2	2009	
P22074	25471	3WTC 4th floor UPS Battery Load Test	3,2	2009	
P22159	22159	Bvr-Repl Bypass Stack Dampers/Foundations	3,2	2009	
P22579	22579	Alarm Monitoring for Communications Technologies	3,2	2009	
P22840	22840	Replace/Rewind Failed Substation Transformers	3,2	2009	
P23089	23091	Rivergate Substation - Replace Digital Fault Recorder	3,2	2009	
P23089	23095	Trojan Switchyard - Replace Digital Fault Recorder	3,2	2009	
P23098	23098	McLoughlin Substation - Replace Obsolete Impedance Relays	3,2	2009	
P23098	25376	Rivergate Substation - Replace Obsolete Impedance Relays	3,2	2009	
P23234	23234	Sherwood-BPA Pearl Fiber Optic Installation	3,2	2009	
P23386	23386	Extend Hemlock-Mason 13 kV Feeder	3,2	2009	
P23438	24588	Hillsboro Substation - SCADA Installation	3,2	2009	
P23456	23456	N Fork-Install New Liner in Prom Park Sewage Lagoon	3,2	2009	
P23784	23999	Woodburn-West OH Reroute & Reconductor	3,2	2009	

Project	Job #	Job Title	Rank	Year	Notes
P23784	24000	Woodburn-Young 13 kV Along Young Rd	3,2	2009	
P23784	24001	Woodburn-West 13 kV Reconductor along Harrision St	3,2	2009	
P23784	24002	Woodburn-Cannery 13 kV Reconductor along Ogle Rd	3,2	2009	
P23784	24003	Woodburn-Cannery 13 kV Reconductor along Parr Rd	3,2	2009	
P23813	23813	Cornell substation - Construct New Sub. with 28 MVA Transf.	3,2	2009	
P23941	23941	BUDGET ONLY - Eng. Contract Design Svcs. Substation	3,2	2009	
P24182	24182	Cyber Security Infrastructure Upgrades	3,2	2009	
P24226	24226	Boardman - Purchase Spare Generator Rotor	3,2	2009	
P24335	24335	Harmony Sub: WR1 Repl. w/2 New Fdr Positions	3,2	2009	
P24335	24390	Harmony Sub: Replace Motor-op Switches with Circuit Switche	3,2	2009	
P24335	24775	Construct Harmony-Lake Feeder	3,2	2009	
P24335	25156	Harmony Sub: Install (2) Getaways	3,2	2009	
P24335	25258	Harmony Sub: Install Conduit for Future Communications	3,2	2009	
P24339	24340	Harrison - Add One 13 kV Feeder Position	3,2	2009	
P24339	24399	Harrison - SCADA Installation	3,2	2009	
P24339	25046	Harrison - Install new feeder getaway	3,2	2009	
P24339	25130	Harrison - Expand feeder backbone	3,2	2009	
P24339	25328	Alder Substation: Remove House	3,2	2009	
P24339	25379	Harrison - Install fiber for SCADA	3,2	2009	
P24608	23391	Extend Carver-Woods & Pleasant Valley-Baxter Feeders	3,2	2009	
P24608	24608	Pleasant Valley WR2 Capacity Addition	3,2	2009	
P24608	25405	Pleasant Valley Add Oil Spill Containment	3,2	2009	
P24623	24937	Replace Town Center-Sunnybrook Getaway	3,2	2009	
P24623	24939	Town Center - Portable Ready	3,2	2009	
P24623	24978	Split Town Center-13 Feeder	3,2	2009	
P24623	25261	Town Center-North getaway	3,2	2009	
P24745	24745	3WTC03 Computer Room UPS Distribution	3,2	2009	
P24758	24758	Oak Grove to Timothy Lake Microwave Upgrade	3,2	2009	
P24805	24805	Meridian Sub.-Add 28 MVA Xfmr, 13 kV metalclad, 115 kV brk	3,2	2009	
P24805	25239	Build 2 new feeders from Meridian WR3	3,2	2009	
P24805	25301	Install pilot relaying at Rosemont substation	3,2	2009	
P24805	25302	Install pilot relaying at Sherwood substation	3,2	2009	
P24805	25304	Build 2 new feeder getaways from Meridian WR3	3,2	2009	
P24812	24812	Build feeder tie to offload Murrayhill-Teal	3,2	2009	
P24835	24835	Dual Monitors at TCC	3,2	2009	
P24838	24838	Software Upgrade for Contact Center Integrated Technologies	3,2	2009	
P24838	24839	Hardware Upgrade for Contact Center Integrated Technologies	3,2	2009	
P24838	25622	Replace Wygant Call Recording - Software	3,2	2009	
P24838	25623	Replace Wygant Call Recording - Hardware	3,2	2009	
P24838	25627	Purchase Customer Callback Software	3,2	2009	
P24838	25628	Purchase Customer Callback Hardware	3,2	2009	
P24838	25630	Upgrade Contact Center Integrated Technologies Fax Services	3,2	2009	
P24843	24843	Beaver-Replace Unit #7 Battery	3,2	2009	
P24855	24855	Backup Communications Upgrade - New NERC Requirements	3,2	2009	
P24855	25420	Coyote Springs - Backup Communications Upgrade	3,2	2009	
P24855	25421	Boardman - Backup Communications Upgrade	3,2	2009	
P24855	25422	Pelton/Round Butte - Backup Communications Upgrade	3,2	2009	
P24866	24866	Purchase Helicopter	3,2	2009	
P24870	20244	Pelton-Paint Tainter Gates & Replace Seals	3,2	2009	
P24976	24976	Purchase Peoplesoft Enterprise Learning Management System	3,2	2009	
P25020	25020	Rockwood - Portable Ready	3,2	2009	
P25140	25140	Carver 13 Reconductor, HWY 224 East	3,2	2009	
P25144	25144	Desktop Equipment - Vintage & Growth	3,2	2009	
P25144	25145	Trojan: Desktop Vintage & Growth	3,2	2009	
P25144	25146	Boardman: Desktop Vintage & Growth	3,2	2009	
P25144	25147	Coyote Springs: Desktop Vintage & Growth	3,2	2009	
P25144	25148	Pelton/Round Butte: Desktop Vintage & Growth	3,2	2009	
P25144	25149	DMS Production Scanner - Vintage Replacement	3,2	2009	
P25144	25607	Personal Technology - Growth	3,2	2009	
P25177	25177	Network Equipment - Vintage Replacement	3,2	2009	
P25177	25212	Network Equipment - Baseline Growth	3,2	2009	
P25224	25224	Brightwood - Install SCADA & Communications	3,2	2009	
P25224	25225	Dunns Corner - Replace Relays	3,2	2009	
P25224	25351	Summit, Install 3-phase PT at 57kV	3,2	2009	
P25224	25409	Welches ground fault protection	3,2	2009	
P25250	25316	Scholls Ferry Substation: Permitting	3,2	2009	
P25250	25370	Scholls Ferry Sub - Transmission Permitting	3,2	2009	
P25446	25446	Boardman - Replace Coal Car Dumper Drives	3,2	2009	
P25452	25452	Boardman - Upgrade AWS Building HVAC Chillers	3,2	2009	
P25483	25483	Rd Butte - Entrance Road Asphalt Paving Improvement	3,2	2009	
P25499	25500	Pelton-Install Transformer Gas Monitoring System	3,2	2009	
P25502	25502	Server Infrastructure Vintage Replacement	3,2	2009	
P25502	25507	Server Infrastructure Growth	3,2	2009	
P25515	25515	CIS Technology Upgrade - Software	3,2	2009	
P25515	25521	Upgrade CIS Technology - Hardware	3,2	2009	
P25519	25519	Bdmn-Upgrade Coal Yard PLC Control System	3,2	2009	
P25579	25579	Microsoft Office Suite Vintage Replacement	3,2	2009	
P25599	25599	Upgrade PBX Software	3,2	2009	
P25599	25600	Upgrade PBX - Hardware	3,2	2009	
P25601	25601	Voice Mail Upgrades - Software Upgrades	3,2	2009	
P25601	25602	Voice Mail Upgrades - Hardware	3,2	2009	
P25621	25621	Coyote Springs - Process Portal upgrade for DCS	3,2	2009	

Project	Job #	Job Title	Rank	Year	Notes
P25624	25624	Intranet Portal to replace PGEWeb	3,2	2009	
P25657	25657	Purchase 2 Meter Services Vehicles	3,2	2009	
PCN089	CN089	Boardman-Purchase Portable Electrical Instruments	3,2	2009	
PCN094	CN094	Boardman-Purchase Minor Tools & Equipment	3,2	2009	
PM9200	M9200	Purchase Replacement Vehicles	3,2	2009	
PM9203	M9203	Emergent Radio Equipment	3,2	2009	
PM9204	M9204	M9204-Unbudgeted Phone Equip/Job Scope Change	3,2	2009	
PM9205	M9205	Emergent Cabling Requirements	3,2	2009	
PMN089	MN089	PURCHASE PORTABLE ELECTRICAL INSTRUMENTS	3,2	2009	
PMN094	MN094	MINOR TOOLS & EQUIPMENT	3,2	2009	
PWN094	WN094	Minor Tools & Equipment-Round Butte	3,2	2009	
P24876	24876	TCC Fitness Room Equipment Replace/Upgrade	3,3	2009	**DISCRETIONARY**
P23421	23421	Pelton-Replace See's Water Supply System	4,1	2009	
P23445	23445	Round Butte-Replace Generator Protective Relays	4,1	2009	
P24747	24747	O Grove-Install Pavement to T Lake Lodge	4,1	2009	
P25426	25426	North Fork-Install Ground Detectors	4,1	2009	
P25426	25432	Oak Grove-Install Ground Detectors	4,1	2009	
P25426	25433	River Mill-Install Ground Detectors	4,1	2009	
P25426	25434	Pelton-Install Ground Detectors	4,1	2009	
P25426	25435	Pelton Reg Dam-Install Ground Detectors	4,1	2009	
P25484	25484	O Grove-Install New Lodge Sanitary System	4,1	2009	
P25490	25490	Pelton - Widen Roadway at Pelton Fish Ladder	4,1	2009	
P25528	25528	Faraday-Upgrade Office HVAC System	4,1	2009	
P25581	25581	O Grove-Create Road Rock Repair Staging Area	4,1	2009	
PX0041	X0041	Hydro & Wind Fitness Capital Job Fund <$150k ea	4,1	2009	
P19750	19750	Upgrade PGE Office Space at World Trade Center	4,2	2009	
P19752	19752	Facility Maintenance Plan	4,2	2009	
P22764	23949	Phase II Upgrade - Oregon City Line	4,2	2009	
P22764	24708	Phase III Upgrade TCC	4,2	2009	
P23596	23596	Expand Fire Protection Systems	4,2	2009	
PM9300	M9300	Purchase of Furnishings for Corporate Use	4,2	2009	
PX0044	X0044	WTC - CRG Placeholder	4,4	2009	
P21663	21663	C Springs-Inst Mini CCW for Air Comp/Aux Boiler	4,5	2009	
P22039	25350	Boardman-Install Type K Pneumatic Controllers - 2009	4,5	2009	
P22676	22676	Beaver-Pave Areas Around Warehouse	4,5	2009	
P24067	24069	Boardman - Install Platforms (2009)	4,5	2009	
P24083	24085	CS - Install Platforms (2009)	4,5	2009	
P24086	24088	Beaver - Install Platforms (2009)	4,5	2009	
P25454	25454	Port Westward - Upgrade the Plant Desuperheaters	4,5	2009	
P25495	25495	C Springs 1-Replace Hydrogen Purge Monitoring Equipment	4,5	2009	
P25518	25518	C Springs-Purchase Spare FD Fan & Rotor	4,5	2009	
P25529	25529	Boardman-Replace Coal Conduit Bends	4,5	2009	
P25530	25530	Coyote Springs 1-Replace FAC Piping	4,5	2009	
P25537	25537	P Westward-Upgrade Diagnostics for Critical Valves	4,5	2009	
P25589	25589	Coyote Springs - Replace telephone system	4,5	2009	
PX0045	X0045	Thermal Fitness Capital Job Fund <$150k ea	4,5	2009	

September 05, 2008

TO: Bob Jenks
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to CUB Data Request
Dated August 22, 2008
Question No. 099

Request:

We understand that PGE employee Pamela Lesh is on loan to NRDC. Who is paying her salary? If it is PGE, how does PGE account for the salary?

Response:

PGE pays her salary. Since May 1, 2008, she has been using the following two accounting strings:

181 - N44012 - 11 - 892 - 00000 - EXCVS (Provide Executive Oversight)
181 - X79199 - 11 - 892 - 00000 - LOAND (Loaned Executive)

Ms. Lesh still spends a portion of her time working for PGE, which is charged to the utility ledger (N44012) while the remainder of her time is charged to the non-utility ledger (X79199).

Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, April 2008 and 2007

(Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Average all classes	
	Apr-08	Apr-07	Apr-08	Apr-07	Apr-08	Apr-07	Apr-08	Apr-07
Oregon	8.57	7.7	8.2	7.83	4.41	4.2	7.4	6.78
Washington	7.49	6.99	6.88	6.5	5.2	4.61	6.78	6.27

	Residential/Average		Commericial/Average		Industrial/Average	
Oregon	1.16	1.14	1.11	1.15	0.60	0.62
Washington	1.10	1.11	1.01	1.04	0.77	0.74

source: Energy Information Administration

October 2, 1987

MARGINAL COST PRICING
SHORT RUN VERSUS LONG RUN[1]

Hethie S. Parmesano
Keith Switzer

I. INTRODUCTION

Economists agree that marginal cost pricing results in an efficient allocation of resources. Briefly, the theoretical argument states: The marginal cost of production is the cost of the resources needed to produce the last increment of output. It represents the value of those resources in their next best alternative use. Price represents the personal value, to the consumer, for the last unit of consumption. It is an indication of the amount of alternative consumption willingly foregone to consume the good in question. When price equals marginal cost, the production cost of the last unit exactly equals the value of that unit to the consumer and resource allocation will be socially optimal. In the market, competitive pressures will work to insure that price equals marginal cost. In a regulated industry, more effort is required to endure the equivalence of price and marginal cost.

Problems sometimes arise when we attempt to implement marginal cost pricing in a regulated environment: (1) marginal cost pricing may lead to a situation where costs are not fully recovered, (2) marginal cost is continuously changing and it is costly to make frequent changes in prices, (3) marginal cost may be very difficult to measure accurately, and (4) marginal cost has been defined in various ways. This

---

1 The material in this paper draws heavily upon the work of Anna P. Della Valle in "Short-Run Versus Long-Run Marginal Cost Pricing" and "Short-Run and Long-Run Marginal Costs" by Anna Della Valle and Miles Bidwell.

paper deals with the question of whether marginal cost pricing should be based on long-run marginal cost or short-run marginal cost, but touches on the other problems as well. As we shall see, the choice between long-run and short-run marginal cost can have significant implications.

II. SHORT RUN AND LONG RUN MARGINAL COST

As previously stated, marginal cost is the cost of producing the last unit of output. There are two ways of looking at these cost: short-run marginal cost (SRMC) and long-run marginal cost (LRMC). In the short run, some factors are fixed. Generally, the size of the capital stock is assumed to be held constant. Given this assumption, the SRMC represents the cost of producing an additional unit output today, using existing capital equipment. The SRMC curve rises as greater amounts of the variable inputs are required to produce additional output from the fixed capital stock. If there is an absolute limit to the amount of production from the existing capital stock, then there is a second element of SRMC -- the cost to potential consumers of having insufficient supply.

The derivation of long-run cost curves requires a different frame of reference. Illustration 1 shows a standard textbook long-run average cost curve (LRAC) -- sometimes called a planning curve. The LRAC curve is an envelope curve derived from connecting all the tangency points of short-run average cost curves (SRAC) reflecting different plant sizes. It shows how minimum costs vary with plant sizes. As plant size and fixed cost increase, the minimum point of successive SRAC curves decreases and then eventually increases. The LRMC curve, by definition, is the curve marginal to the long-run total cost curve. It represents the incremental production cost when all inputs are variable. The LRMC must exhibit the mathematical properties of cutting the LRAC curve from beneath, at the point of minimum LRAC.

The LRAC curve has no time dimension. All it tells us is what costs are to be expected for firms of different sizes at a given moment. Therefore, the LRAC curve does not represent an expansion path. Illustration 1 does not predict the future other than to tell us that if all factor prices remain constant, then the long-run equilibrium price and optimal firm size in this industry will remain constant as well. This long-run equilibrium is, of course, the point of minimum long-run average costs. At this point the LRAC equals the minimum SRAC as well as the SRMC of the most efficient sized firm. If this industry expands, the new firms, at least those that survive, will have average total cost curves such that their minimum average total costs are equal to the minimum LRAC. Over time, all firms that are larger or smaller than the least-cost firm will be expected to either change their size or leave the industry and be replaced by new firms of the optimal size.

Because the LRAC does not represent an expansion path, the LRMC curve marginal to the LRAC has no economic meaning. In the short run, expanded output takes place by existing firms expanding along their own short-run marginal cost curves. In the long run, expansion of the industry takes place by expanding the number of optimally sized firms, never by building firms that are inefficiently too large. Entry into any market is determined by the expected minimum average total costs of a new firm and the expected market price for the new firm's output. If the expected price is larger than the expected minimum average total cost, firms will enter the market. In this way, the price cannot long remain above the minimum average total cost of potential entrants no matter what the cost curves of the industry incumbents.

Two characteristics of the long-run cost curves are worth emphasizing at this point. First, the LRAC and LRMC curves tell us what the cost of production will be if the firm could build the optimal size plant. Thus, unlike the short-run cost curves, all factor inputs, including capital, are assumed variable. Secondly, the long-run cost curves are based on current prices and technology and have no time dimension. The long-run curves assume a sufficient length of time for the firm to adjust all inputs to the most efficient configuration based on today's information. The curves do not apply if technology or relative prices should change in the future.

When properly measured, it is the short-run marginal cost that reflects the actual incremental cost to society imposed by the use of one more unit of output. For greatest overall social efficiency, the consumption decision should be based on this cost. Certainly there is no disagreement that, in competitive industries, prices will always be equal to short-run marginal costs. In fact, it is this equality between price and short-run marginal cost that leads to the social welfare maximizing conditions developed in welfare economics.

III. THE ELECTRIC UTILITY INDUSTRY

The electric utility industry differs from this standard textbook case. Because capacity can be expanded by adding similar units sequentially, the industry is characterized by a much flatter LRAC curve. This situation is illustrated in Illustration 2. In this horizontal range, the LRAC and LRMC curves coincide.

Another important distinction for the electric utility industry is the measurement of SRMC. In the textbook case, the SRMC represented the additional operating cost of using the existing capital equipment to produce an additional increment of output. For the electric utility, SRMC is the sum of the additional operating costs and the change in the cost of reduced system reliability caused by the additional increment of production.

This measure of system reliability represents the costs to society of having an inadequate supply of electricity necessary to meet its demand. As production increases, reserve margins decrease. As the reserve margin decreases, the probability of a shortage increases. This increased probability of a shortage is a component of the short-run marginal cost and should be included in the measurement of SRMC.[2]

IV. USE OF LRMC PRICING IN THE ELECTRIC UTILITY INDUSTRY

Why is it that LRMC has been so widely accepted as a general pricing criteria in the electric utility industry? Four main reasons are commonly cited. They include: (1) the relative stability of LRMC, (2) LRMC's role as a signal of future prices, (3) the equality of LRMC and SRMC in equilibrium, and (4) the revenue requirements argument.

A. Stability of LRMC

The price stability argument rests on the observation that SRMC is much more volatile than LRMC. Proponents of LRMC pricing argue that prices based on a constantly changing measure of marginal cost will be expensive to administer and confusing. As a result, LRMC should be used.

The response to this argument is that there are far better ways of dealing with the stability issue than using LRMC. One solution is to derive an optimal

---

[2] Kent Anderson and Hethie Parmesano's paper "Finding the Short-Run Marginal Capacity Costs of Generation" describes procedures for calculation of marginal shortage costs.

uniform price over time periods with different SRMC using a weighted average of the SRMC's.[5] Only by coincidence or in the case of system optimality would an average of several years' SRMC equal LRMC.

B. LRMC as a Signal of Future Prices

The price signaling argument is based on the notion that current prices should give consumers adequate information regarding future prices. The argument assumes that consumers make purchase decisions based only on existing prices. For example, a consumer who is deciding which refrigerator to buy will base his decision on today's prices and will not anticipate future price changes. Thus, if electricity is going to be more expensive in future years, the current price should reflect that information. This will enable consumers to make efficient long-run decisions.

There are two problems with this argument. First, it ignores the efficiency losses that occur in the short-run due to mispricing of electricity. A consumer's decision whether or not to turn on his air conditioner only affects the utility's costs today and does not have any long term effects. If you intentionally over- or -under-price electricity today in anticipation of a different future marginal cost, then short-run allocative inefficiencies will result. Secondly, the argument assumes that the use of LRMC is the best way to inform consumers about future prices. Such may not be the case. One alternative would be to base prices on SRMC and to publish projections of future prices. In this way, short-term consumption decisions would be correctly based on current costs, and long-term investment decisions could be optimized with respect to the projected future prices.

---

5 See Appendix A of Della Valle's paper "Short-Run Versus Long-Run Marginal Cost Pricing" for the calculation of optimal weighting scheme.

The degree to which this aspect of price signaling is of concern depends greatly on the type of purchase decisions consumers make. There are three main types of purchase decisions: (1) consumption decisions, (2) decisions to purchase short-lived assets and (3) decisions to purchase long-lived assets. Consumption decisions are decisions as to how much to use or consume of the product today. How high to set the thermostat or how long to keep the lights on are two such decisions. Short-lived assets last a limited number of years (typically 2 to 5 years) or are replaced often. For example, consumers tend to replace their entertainment electronics quite often in order to take advantage of improving technology. Long-lived assets are those which represent major household or business purchases and are not expected to be replaced for an extended period of time. A home heating system is an example of a long-lived asset.

Of these three types of purchase decisions, the only one for which future input prices are a major factor is the one involving long-lived assets. When deciding whether or not to install electric versus gas heat for example, the consumer will want to take into account future prices of electricity and gas. Thus, a price based on the LRMC may provide an appropriate price signal to consumers making long-lived purchase decisions provided that LRMC is close to the weighted average of SRMC expected over the life of the long-lived asset. However, LRMC would be inappropriate for consumers making consumption decisions or short-lived asset purchase decisions.

C. Equality of SRMC and LRMC in Equilibrium

The validity of long-run marginal cost pricing is sometimes supported by observing that, in long-run equilibrium, the LRMC is equal to the SRMC as well as to the LRAC. This theoretical equality holds however, only under restrictive assumptions. In particular, the capital stock must be continuously adjusted so as to be of optimal size and mix. This requires prefect foresight on the part of the system planner and the ability to make capital adjustments in small increments.[4] If the electrical system is far from optimal, then SRMC and LRMC may differ by orders of magnitude.

D. Revenue Requirements

It has been argued that LRMC pricing is the only pricing policy that guarantees full cost recovery. This is not necessarily correct even for the special case where long-run marginal costs will be equal to average total costs. Since LRMC is based on static hypothetical cost curves it is likely to differ significantly from the actual costs incurred over time and the annual revenue requirements set by the regulators.

When investment is lumpy and utilities' systems are non-optimal or when economies of scale are significant, pricing at SRMC may raise either excessive or insufficient revenues. However setting price equal to LRMC is not, except by pure coincidence, the most efficient solution to the revenue problem. Rather, the most efficient solution, if politically feasible, is to charge a multi-part tariff consisting of a usage charge equal to SRMC and a flat charge sufficient to meet the required revenue constraint. If it is not possible to charge such a multi-part tariff then the second-best solution is to set price above or below SRMC according to the Ramsey (i.e., inverse elasticity) rule.

---

4 Some utilities have been able to avoid the problem of lumpy capacity additions by judicious sales of their excess capacity until sales growth catches up to installed capacity.

V. THE RATIONALE FOR SRMC IN THE ELECTRIC UTILITY INDUSTRY

The arguments presented above are not intended to imply that LRMC is always an inappropriate pricing tool. In situations where a utility is at or near an equilibrium situation, LRMC pricing may serve as a good approximation to SRMC pricing. This was arguably the case for the electric utility industry through the early 1970's. Between 1949 and 1970, generation capacity and kWh sales were growing fairly steadily, averaging 8.3 and 8.4 percent per year respectively.[5]

The characteristics of the industry today are not consistent with the assumptions necessary for LRMC pricing. Growth in generation capacity has outstripped sales growth by 28 percent since 1970. As a result, the industry has an average reserve margin of 26 percent, compared with 16 percent in 1970.[6] While not conclusive, this increase would indicate that reserve margins may be larger than optimal. Looking at individual utilities, we find reserve margins greater than 50 percent.[7] Certainly, reserve margins of this size would indicate excess capacity. In addition, the unexpected growth of cogeneration and small power production has contributed significant capacity in recent years.

Economic efficiency depends on marginal cost pricing. SRMC has always been the proper measure of marginal cost. Prior to the early 1970's, the difference between short-run and long-run marginal costs in the electric utility industry may have been relatively small. With the existence of excess capacity however, SRMC

---

[5] Figures are based on data in the U.S. Department of Energy Annual Energy Review 1986.

[6] Capacity margins based on Non-Coincident Peak Load, EEI Statistical Yearbook, 1985.

[7] Individual utility reserve margins are from Goldman Sachs Public Utility Survey, June 23, 1987.

diverges significantly from LRMC. As a result, the distinction between the two marginal cost concepts has grown more important.

Prices that include a LRMC capacity charge in the presence of excess capacity will send misleading price signals to consumers. For example, a utility facing a potential loss in sales associated with new industrial cogeneration (or small power production) should evaluate its pricing structure carefully. If prices are based on LRMC, efficiency would dictate dropping the prices to SRMC so that construction of additional capacity with costs higher than the utility's SRMC is not encouraged. The same point applies to other customers with elastic demands. The use of LRMC pricing will only exacerbate the excess capacity problem.

VI. SUMMARY AND CONCLUSION

Economists agree that marginal cost pricing results in an efficient allocation of society's resources. In the electric utility industry, marginal cost pricing has not typically been based on short-run marginal cost. The use of long-run marginal cost pricing has been justified on grounds that LRMC is stable, is a good indicator of future prices, is equal to SRMC, or is necessary for full cost recovery. Although there are problems with these arguments, the use of LRMC may have represented a good approximation to SRMC pricing through the early 1970's.

Changes in the industry over the past 15 years have forced utilities to recognize the distinction between SRMC and LRMC. Specifically, too much or too little capacity or the wrong mix of capacity cause SRMC and LRMC to diverge from one another. Given this divergence, marginal cost pricing based on LRMC is efficient only by coincidence. It is particularly important for electric utilities faced with additional cogeneration capacity or loss of sales to other customers with elastic demands to set prices according to SRMC.

Illustration 1

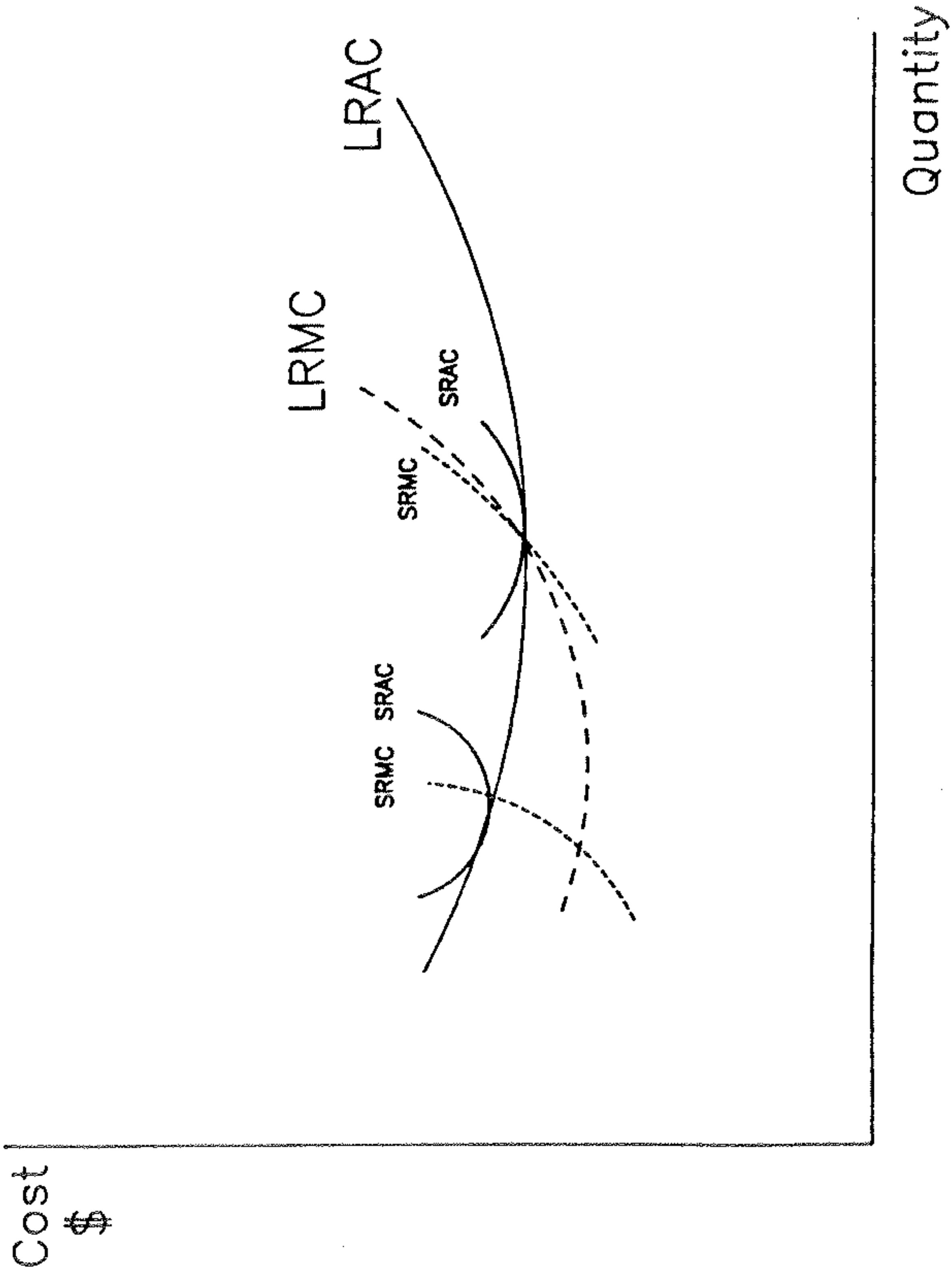
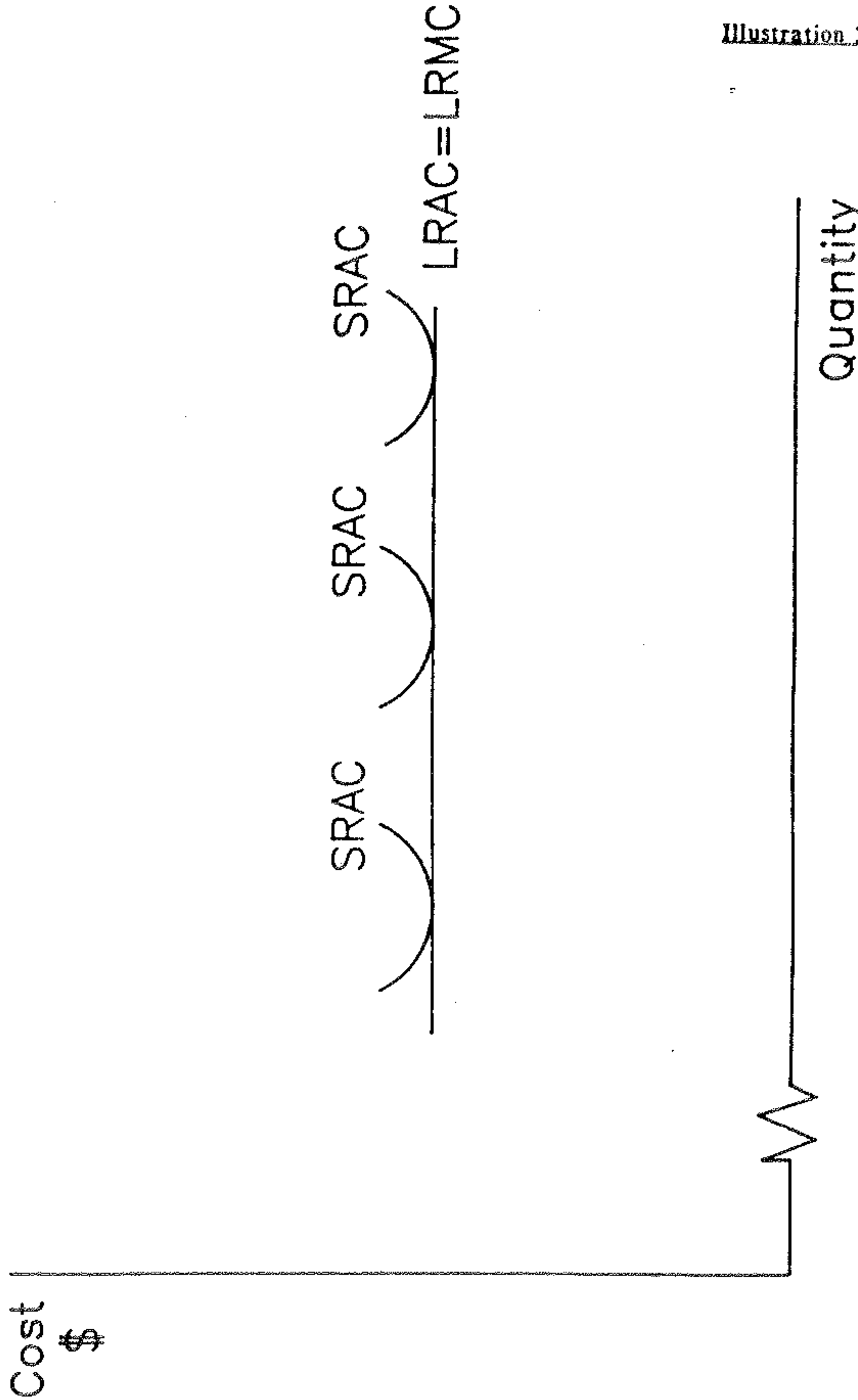


Illustration 2



(intentionally blank)

UE 197 – CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of September 2008, I served the foregoing Surrebuttal Testimony of the Citizens' Utility Board of Oregon in docket UE 197 upon each party listed, by sending a non-confidential version via email and, where paper service is not waived, by U.S. mail, postage prepaid, and by sending a confidential version to the appropriate parties as identified on the service list by U.S. mail, postage prepaid, and upon the Commission by emailing a non-confidential version and by sending 6 confidential copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

Bob Jenks

Bob Jenks
The Citizens' Utility Board of Oregon

JIM DEASON, ATTORNEY AT LAW
1 SW COLUMBIA ST, SUITE 1600
PORTLAND OR 97258-2014
jimdeason@comcast.net

W JESSE D. RATCLIFFE, ASSISTANT ATTORNEY GENERAL **(C)**
1162 COURT ST NE
SALEM OR 97301-4096
jesse.d.ratcliffe@doj.state.or.us

BOEHM KURTZ & LOWRY
KURT J BOEHM, ATTORNEY **(C)**
36 E SEVENTH ST - STE 1510
CINCINNATI OH 45202
kboehm@bkllawfirm.com

MICHAEL L KURTZ **(C)**
36 E 7TH ST STE 1510
CINCINNATI OH 45202-4454
mkurtz@bkllawfirm.com

W CITIZENS' UTILITY BOARD OF OREGON
OPUC DOCKETS
610 SW BROADWAY STE 308
PORTLAND OR 97205
dockets@oregoncub.org

ROBERT JENKS **(C)**
610 SW BROADWAY STE 308
PORTLAND OR 97205
bob@oregoncub.org

W COMMUNITY ACTION DIRECTORS OF OREGON
JIM ABRAHAMSON, COORDINATOR **(C)**
PO BOX 7964
SALEM OR 97301
jim@cado-oregon.org

DAVISON VAN CLEVE PC
S BRADLEY VAN CLEVE **(C)**
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mail@dvclaw.com

DEPARTMENT OF JUSTICE
JASON W JONES, ASSISTANT ATTORNEY GENERAL **(C)**
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
jason.w.jones@state.or.us

JANET L PREWITT, ASST AG **(C)**
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

MICHAEL T WEIRICH, ASSISTANT ATTORNEY GENERAL **(C)**
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
michael.weirich@doj.state.or.us

W FISHER SHEEHAN & COLTON
ROGER D. COLTON **(C)**
34 WARWICK RD
BELMONT MA 02478
roger@fsconline.com

LEAGUE OF OREGON CITIES
SCOTT WINKELS, INTERGOVERNMENTAL RELATIONS ASSOCIATE
PO BOX 928
SALEM OR 97308
swinkels@orcities.org

W OREGON DEPARTMENT OF ENERGY
KIP PHEIL **(C)**
625 MARION ST NE - STE 1
SALEM OR 97301-3737
kip.pheil@state.or.us

W OREGON ENERGY COORDINATORS ASSOCIATION
JOAN COTE, PRESIDENT **(C)**
2585 STATE ST NE
SALEM OR 97301
cotej@mwvcaa.org

PORTLAND GENERAL ELECTRIC
PATRICK HAGER, RATES & REGULATORY AFFAIRS **(C)**
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

DOUGLAS C TINGEY, ASST GENERAL COUNSEL **(C)**
121 SW SALMON 1WTC13
PORTLAND OR 97204
doug.tingey@pgn.com

PUBLIC UTILITY COMMISSION
JUDY JOHNSON
PO BOX 2148
SALEM OR 97308-2148
judy.johnson@state.or.us