BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

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

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

REDACTED

June 4, 2010

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

I. Introduction

CUB is sponsoring three pieces of testimony. Two pieces are being jointly submitted with ICNU – Mike Gorman's testimony on revenue requirement and Ellen Blumenthal's testimony on wages and salaries and accounting deferrals.

A settlement in principle has been reached on some issues in this docket, but a stipulation has not been finalized and filed with the Commission. The following testimony is written with the assumption that the parties can finalize an agreement on those "settled in principle" issues. If an agreed upon stipulation cannot be finalized, CUB may seek to address additional issues.

In this piece of testimony CUB would like to address the following issues:

- PGE's attempt to change the current regulatory paradigm will shift risk from shareholders to customers by changing the structure of the PCAM and adding a series of new regulatory mechanisms.

- PGE's rate base will likely lead to a violation of the used and useful principle.

- PGE's decoupling mechanism will overcollect fixed costs.

II. PGE's Attempt to Shift the Regulatory Paradigm

PGE puts forth a number of proposals in this filing that are designed to reduce earning volatility. Taken individually, each of these measures would shift risk from shareholders to customers. Taken as a package, these proposals have to be viewed as a rewriting of the regulatory paradigm in a way that greatly favors the Company at the expense of its ratepayers.

A. PGE's proposal would effect a dramatic change in Oregon regulation.

While much of this docket concerns PGE's request for an increase in rates to reflect reductions in load due to the recession, higher costs, and a desire for a higher ROE, Mr. Piro lists a series of "Policy Proposals" that the Company is proposing:

A pension automatic adjustment clause tariff to forecast pension expense, track and amortize differences between expected and actual pension expense, and recover financing costs associated with net pension-related cash flows. . . (PGE Exhibit 500).

A balancing account for tracking and recovery of costs associated with future major storm damage. PGE formerly purchased insurance coverage for major storm damage... (PGE Exhibit 800).

Continuation of the Power Cost Adjustment Mechanism (PCAM) and Automatic Update Tariff (AUT), with alteration of the PCAM to make the deadbands symmetrical and narrow their overall size to $10 million. PGE also proposes to include collateral costs associated with power supply operations as net variable power costs for ratemaking purposes and include them in the PCAM/AUT going forward… (PGE Exhibit 400).

An automatic adjustment tariff related to recovery of our remaining investment in the Boardman Power Plant to align recovery with a Commission decision to alter the operating life of the facility. . . (PGE Exhibit 300).

An accounting Order that allows PGE to track differences between the environmental mitigation and remediation costs as projected in this case for certain established projects and the corresponding actual costs . . . (PGE Exhibit 700).

An accounting Order that allows PGE to accrue long-term debt on study costs of self-build options for IRP/RFP purposes . . . (PGE Exhibit 300).

An accounting Order that allows PGE to smooth the impact of O&M costs related to the Information Technology (IT) system replacement program . . . (2020 Vision). (PGE Exhibit 600).

Continuation of the decoupling mechanism approved by the Commission as a two-year pilot in UE 197 . . . (PGE Exhibit 1500).[1]

The common theme with these proposals is that they reduce earnings volatility by shifting risk from shareholders to customers.

The PUC sets rates, it does not approve costs. In order to set rates, costs are forecast to determine the rate that will allow the Company to recover its prudently incurred costs and earn a reasonable rate of return. However, the forecast will almost always be inexact. Costs will not be as they are forecast, nor will demand. The

[1] UE 215/ PGE / 100 / Piro / 16-17.

shareholder return will not be at the point that is established as the "authorized amount." Once the rate is established on this forecast of costs, the Company is generally expected to manage its business to the rates. Some costs may be higher, and some costs may be lower, and the Company is expected to manage its operations within the rates that were established. When costs grow outside of the utility's ability to manage within the current rates, the utility files a new rate case and new rates are established, based on new forecasts that will also be inaccurate.

None of PGE's "policy proposals" focus on ratemaking - which is the primary role of the PUC - or the ratemaking exercise within which we are currently engaged. Instead, PGE's "policies" focus on the areas that are known to be misforcast: costs and demand. PGE is asking that customers take the risk that its forecasts of costs and demand are wrong. Under its proposal, PGE will no longer be expected to manage its business to its rates, but its rates will constantly be adjusted to levels that correspond to its costs. PGE will no longer have an incentive to control its costs. The jobs of Staff and intervenors will become much more difficult, because instead of relying on PGE's incentive to manage its costs, the regulatory system will rely on after-the-fact prudence reviews to create an incentive for PGE to prudently manage its costs.

For customers, this is also a change. Customers will no longer really know the cost of their electricity, because rates will be subject to so many true-up clauses. To understand the cost of electricity, a customer will, under the PGE proposal, have to take current rates, subtract the amount in those rates that represents true-ups from previous years of power costs, pension costs, storm damage costs, environmental cleanup costs, information technology costs, and changes in demand, and then add in the amount in future rates that represents true-ups from the current year for all of the same variables. Customers simply will not know the "actual" cost that the Company is putting on the system, and rates will be less reflective of "accurate price signals."

B. PGE is attempting to reduce earning volatility, but one purpose of equity shareholders is to allow earning volatility.

The testimony of PGE witness Steven Fetter, of Regulation UnFettered, makes clear that the purpose of the changes that PGE is proposing in the PCAM is to reduce the chance of the Company earning less than its authorized amount.[2] Undoubtedly, investors, investment banks and rating agencies would love to see no volatility in earnings; the opportunity to earn an equity-based return without an equity-based risk is indeed appealing to investors. But removing this risk eliminates one of the primary purposes of having an investor-owned utility - investors assume a portion of the risk of losses in exchange for the potential to earn a rate of return.

There are two sources of capital for the purposes of providing public utility service. The first is debt. Debt costs less than equity, but creditors have a right to demand repayment of debt. Utilities that cannot meet their debt schedule could face bankruptcy. Shareholder equity costs more than debt, but payments to shareholders are not guaranteed, so they can act as a bit of a shock absorber, going up and down as needed. If PGE's goal is to change the regulatory process to eliminate earnings volatility, then customers would be better off with more leverage and less equity in the capital structure (or moving to public ownership, where there is no equity at all).

[2] UE 215 / PGE / 1300/ Fetter / 14.

This is a fundamental dilemma and contradiction in regulated utilities. Shareholders want guaranteed returns, but if they get them, then customers would be better off without the Company having any shareholders.

C. PGE is proposing these mechanisms to stabilize earnings, but much of its earnings volatility will be unaffected by its policy proposals.

PGE's earnings have regularly been below the level authorized by the PUC, but much of the cause of the deficit in earnings will be unchanged by PGE's current policy proposals presented in this docket.

CUB Exhibit 102 is a PGE PowerPoint of a recent presentation to potential investors. The PowerPoint can be found on PGE's website. In it PGE lists the key factors that have affected its earnings over the last three years[3]:

Key Items that have affected PGE's Earnings ($/diluted share)		
2007	**2008**	**2009**
Boardman deferral (+$0.26)	Trojan Refund Order Provision (-$0.32)	Boardman Deferral (-$0.15)
California settlement (+$0.06)	Non-qualified benefit plan assets (-$0.19)	Selective Water Withdrawal (-$0.05)
Non-qualified benefit plan assets (-$0.05)	Beaver oil sale (+$0.10)	Non-qualified benefit plan assets (+$0.07)
Senate Bill 408 (+$0.18)	Senate Bill 408 (-$0.10)	Senate Bill 408 (-$0.11)

[3] CUB Exhibit 102, page 24.

Most of the items in this list - Boardman deferral, Trojan refund, California settlement, Selective Water Withdrawal and SB 408 - are unlikely to be affected by PGE's proposed mechanisms to stabilize earnings.

i. 2009 and 2010 earnings have been hit hard by a reduction in industrial demand.

Industrial demand fell by 10.2% in 2009, a decline approximately 8 times greater than in commercial load.[4] Mr. Piro points out that if PGE's forecast from UE 197 had been accurate, the Company would have earned an additional $54 million.[5] This underforecast was due to economic conditions, and has resulted in PGE taking a significant hit to earnings. PGE is not, however, responding by recommending that industrial customers be added to the decoupling mechanism. Without such a change, the Company is accepting the fact that it will continue to take the risk to its earnings of economic recessions affecting industrial customers. Of course, that is not a problem in the short term, as the Company is adjusting forecasts of industrial demand and reassigning fixed cost recovery based on that demand. This means that without including industrial customers in decoupling, PGE's shareholders stand to benefit as industrial demand recovers.

ii. Boardman issues.

PGE has had to take a series of write-offs associated with the 2005-06 Boardman closure. In February 2010, the PUC found that PGE had been imprudent in its operation of the Boardman plant and ordered the Company to write-off $13.2 million that had been deferred for later inclusion in rates.[6] The Commission had earlier allowed deferral of

[4] UE 215 / PGE / 1400/ Nguyen / 2.
[5] UE 215 / PGE / 100 / Piro / 2.
[6] OPUC Order No. 10-051, page 15.

$26.4 million of the $45.7 million cost of the outage, resulting in a write-off of $19.3 million.[7]

In addition to these write-offs, there were two more periods of higher costs that PGE did not even request recovery of, so there was never a factual determination of the cost by the OPUC. PGE filed for the deferral on November 18, 2005, 23 days after Boardman was taken out of service because of serious vibration issues that had arisen in the low pressure turbine.[8] Because PGE waited until November 18 to file the deferral, costs incurred before that time were not eligible for recovery. Finally, there was an accident in February when PGE brought the plant back online, which led to a second Boardman outage. That extended outage lasted well into 2006. PGE did not seek recovery of the costs associated with this second Boardman outage,[9] so there was never a factual determination of the outage or a prudence review to determine whether the Company was at fault.

The Boardman outage of 2005-06 forced PGE to undertake two write-offs totaling $32.5 million, and two additional write-offs of an undermined amount. One write-off was explicitly due to PGE's imprudence, making it ineligible for recovery under any mechanism. The two additional write-offs were related to costs that were never determined to be prudent, making them ineligible as well. The final write-off was a PUC determination of a fair sharing of costs between customers and shareholders. While PGE's proposal for a PCAM could reduce this write-off, it is the only one of the four that could be implicated by PGE's proposals to stabilize earnings.

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[7] OPUC Order No. 07-049.
[8] UM 1234 / PGE / 400 / Lesh – Tinker / 3.
[9] OPUC Order No. 07-049.

iii. Selective Water Withdrawal.

Last year, PGE experienced a major accident that caused a delay in the construction of the Selective Water Withdrawal Project. This led to a stipulation that reduced PGE's allowed costs in order to ensure that customers were not being charged higher costs due to the construction accident. The total write-off was [redacted].[10]

iv. Trojan litigation.

After more than a decade of litigation, the PUC ordered PGE to refund $33.1 million related to the closed Trojan nuclear plant.[11] While there is a long history to the Trojan case, its relevance here stems from the fact that none of the mechanisms that PGE is now proposing would have impacted the Trojan refund that PGE was ordered to pay.

If PGE's proposals for new regulatory mechanisms would not have affected much of the earnings volatility that the Company experienced, what is the benefit of making such changes? And what are the risks of making such changes, when they do not seem necessary?

D. PGE's proposal to rewrite the regulatory structure will overwhelm a regulatory system that is already stressed to near its breaking point.

Currently, PGE has an incentive to manage its costs, because once rates are in effect, the management of most costs affects earnings. This system allows a well-managed utility to earn above it authorized ROE by reducing costs. In Oregon, there is not a history of Staff or intervenors initiating rate cases designed to reduce rates when a utility is overearning. Thus in the 1990s when power costs were falling, PGE was able to take advantage of this ratemaking tradition and earn above its authorized ROE.

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[10]CUB Exhibit 103 Confidential.
[11] OPUC Order Number 08-487, page 1.

PGE is now proposing to change this tradition by instituting a series of mechanisms that will automatically true up costs. The consequence of this change will be to overwhelm the regulatory system. First, each new mechanism will lead to additional proceedings which will require even more work of Staff, the Company and intervenors. Second, rather than maintaining the current incentive structure to ensure proper management of utility costs, Staff and intervenors will have to rely on prudence reviews in order to watchdog the Company. Prudence reviews are much more time consuming ro prepare and litigate.[12]

i. Each mechanism will lead to additional work.

New tracker mechanisms, such as the proposed storm cost tracker, and the environmental cleanup tracker will likely need some sort of annual process to ensure that the costs that are going into the tracker are real and are prudent. In years where any costs in the tracker are amortized into rates, there will be an additional proceeding to determine which costs should be allocated to customers and what rate spread should be used for those costs. Thus each new mechanism will lead to several additional proceedings.

ii. Prudence reviews will be necessary.

Because under current regulation, most reductions in costs between ratecases benefit shareholders, utilities have an incentive to control costs. Reducing the role of this incentive will force Staff and intervenors to rely on prudence reviews to ensure that the utility is managing its costs properly. One PGE witness thinks this is a good thing. According to PGE witness Steven M. Fetter, of Regulation UnFettered:

> I view the earnings test, as structured, as an imperfect attempt to compel appropriate utility behavior, at the expense of sacrificing the goal of recovery of actual prudent costs with customers paying no more, no less.

[12] CUB believes that UE 196 and UM 995 are examples of the workload associated with prudence reviews.

> Such a framework ignores the greatest hammer that a utility regulator holds – the authority to review the prudency of a company's resource procurement activities with the ability to disallow imprudent expenditures. While that regulatory exercise may not pinpoint precisely actual costs going into rates, from my experience, it comes pretty close.[13]

Substituting the hammer of prudence reviews for the incentive of managing costs to current rate levels as the primary tool to ensure proper utility management of costs is a significant change. CUB does not believe that this is a good change for Oregon.

There have been three dockets where CUB has attempted to examine a utility's conduct for prudence: in UE 196, we looked at the prudence of Boardman; in UM 995, we looked at the prudence of PacifiCorp's long term power sales contracts; and in UE 88, we looked at the prudence of Trojan. A review of UE 196, UM 995, and UE 88 shows that prudence reviews are long, and difficult. Utilities are less likely to admit to imprudence than they are to a financial write-off, so prudence reviews are harder to settle. Prudence reviews are also much more likely to lead to litigation appealing OPUC decisions. Since 1990, CUB has twice appealed OPUC decisions. Both challenges grew out of dockets where we mounted prudence challenges (UE 88 and UM 995). In UE 196, while CUB did not appeal to Oregon Courts, another party did.

CUB strongly disagrees with PGE's witness, Mr. Fetter. CUB believes relying on prudence reviews to incent good cost management will be harmful to Oregon's regulatory system and will cost every both more money and more time.

E. PGE's proposals are designed to allow recovery of costs even when PGE is overearning.

The costs that PGE is proposing to shift into trackers (environmental cleanup, storm accounting, etc) are costs that are eligible for deferral. Because these costs are modeled in

[13] UE 215 / PGE / 1300 / Fetter / 15.

rates, a deferral would likely be subject to a test to ensure that the cost is "substantially" above the amount already forecast in rates. Moving these costs to a tracker not only removes the "substantial" test, but would make these costs no longer subject to an earnings test.

There is an important reason that deferrals are subject to an earnings test. If a utility is earning above its authorized levels to such a degree that it can absorb a deferral and still be earning at a reasonable level, then its current rates are fair, just and reasonable, even recognizing the cost that is deferred. There is, therefore, no reason to raise rates. Since the primary purpose of regulation is to set rates, not to approve costs, if rates are set at fair, just and reasonable levels in relationship to a utility's costs, then the regulatory system has been successful.

Trackers, however, are not subject to an earnings test. Higher costs one year are offset against lower costs another year, not offset against earnings. If there is a tracker for environmental cleanup costs and those costs are above what is in rates, but less than the amount that the utility is overearning, then in a deferral the overearning is essentially used to pay for the higher environmental cleanup costs. Under a tracker, PGE would keep track of the higher environmental cleanup costs, keep its overearning, and later either offset environmental cleanup costs when they are lower than forecast or raise rates to recover the environmental cleanup costs. Customers would pay the higher costs, while the Company would retain the overearning.

III. CUB's view of the specific mechanisms PGE is proposing to use to shift risk.

So far, CUB has discussed PGE's proposals to shift risk generally. Now we will review the specific mechanisms PGE is proposing and the evidence PGE argues supports the many changes it proposes.

A. Power Cost Adjustment Mechanism.

PGE is proposing significant changes to the PCAM. PGE would remove the asymmetrical deadband, reduce the deadband on both sides to a flat $10 million, and eliminate the earnings band, while retaining an earning test.[14]

i. The PCAM is working and does not need to be changed.

CUB opposes PGE's proposed changes to the PCAM. The PCAM has only been in effect for three years, and it seems to be working as intended. PGE's primary argument for changing the mechanism is that the investment community does not like it:

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

CUB does not believe that the investment community's opinion is quite as strong as PGE suggests. More importantly, the PCAM is working exactly as it is intended to work. Both Ms. Pope and Mr. Fetter suggest that the PCAM is poorly designed because it

[14] UE 215 / PGE / 200 / Pope / 23.
[15] *Ibid*, page 21.

does not ensure PGE will recover every dollar of prudently-incurred power costs. But as CUB has said repeatedly, this is not the purpose of regulation. Utility rate regulation is primarily designed to set rates, not approve costs. Costs are forecast, rates are set, and a utility is expected to manage its costs within those rates. Ensuring recovery of prudently-incurred costs is not the function of regulation. Allowing the opportunity to recover prudently incurred costs, if the utility can manage its operations within its rates, is all regulation should give a utility.

The fact that PGE would like a smaller deadband in the PCAM is not surprising, as that is what the Company wanted when the OPUC originally adopted the current mechanism. But, since the PCAM's adoption, the economy has gone into recession, industrial demand has reduced, and power markets have settled down, so there is generally less risk associated with power cost variations. Indeed, CUB believes that there is less risk in power markets today than when the Commission approved the PCAM. CUB Exhibit 104 shows EIA forward power cost projections. According to EIA, utility generation costs are expected to decline from 6.4 cents/kWh in 2009 to 5.4 cents/kWh in 2011. Prices will then stay below 6 cents/kWh for the next decade. This shows a great deal of stability. If costs are more stable than when the PCAM was adopted, it is not clear why the OPUC should change the mechanism to reduce volatility.

According to PGE, the PCAM has been in operation for three years and has only led to money changing hands once. In the other years, cost differences between what was forecast and what was actually incurred were absorbed by the power cost deadband and the earnings deadband. This is a result that is consistent with the design. The goal with the PCAM is to avoid deferrals by pre-establishing the sharing criteria that would be used in a deferral. Even PGE would probably agree that power costs are a stochastic risk. Under Commission policies, these costs are subject to a deferral only after they reach a substantial level. Without a PCAM, it would be unlikely that the OPUC would approve power cost deferrals every year. As stated in the Commission order that created the PCAM, the mechanism is meant to "capture power cost variations that ***exceed*** those considered part of normal business risk."[16]

In addition, PGE opposes the earnings deadband, because:

> The earnings test deadband effectively acts as a second deadband above and beyond the power cost variance deadband. A PCAM should not provide for over-earning when power costs are lower and under-earning when costs are higher.[17]

CUB again disagrees. The earnings deadband works exactly like it was designed to work. The PCAM does not "provide for over-earning when power costs are lower and under-earning when costs are higher," because reasonable earnings are a range, not a specific point. While the PUC will establish a single point and call it the allowed return on equity, it is generally set as a point somewhere within a range of reasonable outcomes. Earning 100 basis points above the authorized amount does not define overearning. Instead, in this case the Commission is using 100 basis points to define the upper band of "reasonable" earnings and 100 basis points below the authorized level as the lower band of "reasonable" earnings. If PGE is in this range is it neither overearning nor underearning. It is earning a reasonable return.

[16] Order No. 07-015, page 26. (emphasis added)
[17] UE 215 / PGE / 200 / Pope / 24.

ii. PGE overstates the investment community's concerns over the PCAM.

Both Ms. Pope and Mr. Fetter go to great lengths to claim that changing the PCAM and shifting risk onto customers is necessary to please the investment community. According to Mr. Fetter:

> Consistent with these views, S&P recently explained how recovery mechanisms, like PGE's PCAM, can play a key role in providing a regulated utility with timely recovery of prudent expenditures, thereby helping to mitigate the negative effects from regulatory lag:
>
>> ...there are ratemaking alternatives that can eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in an onerous construction program. Instead of significantly large rate base increases or lengthy rate moderation or phase-in plans, separate tariff provisions that allow for timely rate recognition during construction, without requiring a utility to file a formal rate case application, can gradually ease higher costs into rates, limiting the accumulation of financing costs. ... the greater the percentage of a utility's rates that it recovers through fixed charges rather than volume based charges, the greater the support for credit quality.[18]

The main problem with this argument is that the quote Mr. Fetter includes from S&P does not address recovery mechanisms like PGE's PCAM. Instead, the quote refers to rate case lag during capital construction (for renewable investment this is avoided with Oregon RAC clauses), the need to allow construction work in process, and the need for higher fixed charges rather than volume-based charges. This is not to say that S&P would not prefer a different PCAM. If they were in charge of regulation, it would not be surprising if the PCAM was different, if CWIP was allowed, if industrial customers and weather were included in the decoupling mechanism, and deferrals and trackers were widely used. But S&P's goal forcus is not on "fair, just and reasonable rates," and S&P is not the regulator.

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[18] UE 215 / PGE / 1300 / Fetter / 13.

Mr. Fetter also states that "Moody's agrees on the importance of regulation – and recovery of prudent expenditures – in the determining of credit ratings." He goes on to quote Moody's:

> Moody's agrees on the importance of regulation – and recovery of prudent expenditures – in the determining of credit ratings: For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. ... However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions. ...
>
> The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant.[19]

Again, this quote does not state a direct concern with the structure of PGE's PCAM. While it states that fuel and purchased power cost recovery is good, both PGE's AUT and its PCAM are mechanisms designed to allow recovery of fuel and purchased power costs. The other issues - utility mergers, ring fencing, pre-approval of new investments, and timely recovery of capital investment - have little to do with the PCAM.

There is a reason that the above quote from Moody's does not say anything about PGE's PCAM. Moody's actually likes PGE's PCAM. CUB Exhibit 105 is a confidential report from Moody's that states:

[19] UE 215 / PGE / 1300 / Fetter / 15.

[redacted]

CUB's review of PGE confidential workpapers 1300 that were submitted with this filing shows a mixture of different views from investment firms. While many are disappointed with PGE's recent earnings, they point to different reasons for those earnings and have different views of the future. It is clear that they do not see reducing deadbands on the PCAM as a magic bullet that will solve PGE's problems.

Finally, CUB notes that not all of the recent concerns about PGE relate to either its management or to available regulatory mechanisms. Financial advisors have expressed clear concern about the OPUC itself:

[redacted][21]

B. Storm Accounting.

PGE seeks to create a balancing account for "Level III" Storm damage that would be reviewed at least every two years.[22] PGE proposes that it collect $4.5 million per year

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[20] CUB Confidential Exhibit 105.
[21] CUB Confidential Exhibit 106.
[22] UE 215 / PGE / 800 / Hawke – Nicholson / 13.

for storm damage, with $3.5 million going into a balancing account. Each year, any Level III storm costs above $1 million would go into the balancing account.[23] Costs that flow into the balancing account would be subject to a prudence review and/or an audit.[24]

CUB disagrees with PGE's proposal. It is one thing to have special ratemaking procedures for power costs, taxes, or renewable investments, each of which are in the hundreds of millions of dollars; it is quite different to have a special ratemaking procedure for a cost that is, on average, less than $10 million per year.

PGE tries to paint this as a straightforward mechanism, but it is not. This balancing account will place additional burdens on a regulatory system that is already under stress. First, before items can be placed into the balancing account, a determination must be made as to whether the storm is Level I, Level II, or Level III. PGE's testimony includes the following table, which shows how these events are classified:[25]

Table 4
PGE Classifications for Outages

Level I - refers to typical daily occurrences on the distribution system. These outages will increase phone calls from customers, but should not cause a hardship on call center staff. The following activities are considered Level 1 incidents:	·Two feeders out in service territory. ·Two thousand customers or less out of service at multiple locations. ·Restoration can be completed in less than 24 hours.
Level II – this level increases substantially the number of calls due to outages. Typically, two or less regions are involved and restoration can be completed with PGE resources. The following activities are considered Level II incidents:	·Four or more feeders or multiple tap lines out of service. ·20 to 30 thousand customers out of service at multiple locations. ·Restoration can be completed in 48 hours. ·Incident may generate media attention.
Level III – at this level, many customers will be out of service. Call center will generally require support from other areas of the company to support customer calls. Management will contact other utilities for possible assistance in restoration efforts. The following activities are considered Level III incidents:	·Multiple substations and feeders out of service. ·Greater than 50,000 customers out of service. ·Three or four regions are experiencing outages. ·Greater than 72 hours to restore service. ·Outside assistance may be required.

[23] *Ibid*, page 14
[24] *Ibid*, page 12.
[25] UE 215 / PGE / 800 / Hawke – Nicholson / 11.

Currently, the methodology by which storm damages are classified is not a ratemaking issue. However, if this mechanism is adopted, there will suddenly be ratemaking implications to what level of classification a storm receives. Based on the above table, we can be assured that this will become a disputed issue. If a storm involves 48,000 customers and takes 62 hours to restore service, it is larger than a Level II storm but smaller than a Level III storm. If a storm involves fewer than 30,000 customers, but takes more than 72 hours to restore service, it can be classified as either a Level II or a Level III storm. Once this classification becomes a ratemaking issue, disputes will have to be decided by the Commission. Because the above table does not have enough detail to classify every storm with certainty, a balancing account will require further work to define which storms are considered Level III. The Commission, Staff and intervenors have spent a great deal of time over the last few years trying to deal with the issue of how to classify and account for Forced Outage Rates. CUB recommends that we do not set ourselves up for a similar process to classify storm outages.

Determining a factual basis for classifying storm damage as Level III is only the first step. Each year, the costs that are charged to the balancing account will have to be audited to ensure that only costs associated with repairs for Level III outages are allowed. This may seem like a straightforward process, but will likely lead to disputes over whether such costs are incremental or already included in base rates. For example, when existing salaried employees are shifted into the Call Center during an outage, what cost is booked to the balancing account? Then, once the set of costs that are actually incremental and related to the Level III storm has been identified, a separate examination of the expenditures will be necessary to ensure that they were prudent.

PGE forecasts average annual storm costs to be $4.5 million[26], out of a revenue requirement of $1.8 billion.[27] This means that storm costs are approximately 0.2% of PGE's revenue requirement. CUB does not believe that a balancing account for storm damage comes close to being worth the regulatory effort.

C. Environmental Cleanup Costs.

PGE is also proposing a tracker for environmental cleanup costs, which the Company forecasts at $3.6 million in the test year.[28] This cost is smaller than storm damage, and represents less than 0.2% of PGE's revenue requirement.

PGE proposes to track the difference between what is established in rates and the actual cost of cleanup of Superfund and Superfund-like sites. PGE explains how the balancing account would benefit customers:

> **Q. What are the benefits to customers of this balancing account mechanism?**
>
> Environmental projects can sometimes take decades to resolve. During this time, it is very difficult to accurately forecast costs and potential insurance proceeds received that offset these costs. The balancing account minimizes volatility by enabling PGE to track actual costs versus forecasts, and review (and reset, if necessary) the account on a regular two-year cycle.[29]

CUB is not sure how this account represents a benefit to customers. The volatility of a cost that represents such a small part of PGE's revenue requirement is not a problem for customers. CUB also believes that this balancing account has the potential to cause more work than it is worth. Like the storm costs, environmental cleanup costs will have

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[26] UE 215 / PGE / 800 / Hawke – Nicholson / 11.
[27] UE 215 / Pretrial Brief / page 7.
[28] UE 215 / PGE / 700 / Quennoz – Behbehani / 34.
[29] Ibid. p. 41-42

to be reviewed to ensure that they are incremental and don't represent costs or personnel that are already included in base rates.

These costs will also be subject to prudence reviews. Quite frankly, CUB is not sure if it is in PGE's interest to separate out these costs in a manner that highlights them and leads to an individual prudence review. Because a prudence review would not be limited to the cleanup program itself, it could lead to a prudence review of the activity that led to the environmental damage, even when that activity occurred decades ago.

Regardless of whether it is in PGE's interest, CUB does not believe it is in the interests of customers or the regulatory system to create a significant amount of work around a small amount of dollars. CUB suspects that PGE's primary concern is that there is potential for environmental cleanup costs to grow and ultimately become a more significant component of the Company's costs. CUB acknowledges that this potential exists, but suggests that mechanisms such as deferrals (or maybe even trackers) are available if the costs do become significant. However, this is an issue that should not be addressed until the costs do become significant enough to justify the proceeding.

D. Self-Build Study Costs.

PGE is also seeking an accounting order which would allow the Company to accrue financing costs associated with all self-build study costs, including:

1) Analysis of the site and technology, including fueling, transmission and water studies;

2) Securing land agreements;

3) An assessment of environmental site considerations and permitting feasibility to obtain relevant state and federal permits; and

4) Preparation and filing of required documents for permitting costs from the time incurred.[30]

PGE then requests that it be allowed to recover these costs regardless of whether the self-build option is chosen or not. By having a regulator allow PGE to track these costs and charge them to ratepayers who have no choice but to pay them, PGE claims this will put them on an "equal footing with other going concerns that may bid in an RFP."[31]

This approach doesn't create an "equal footing" -- other bidders in an RFP do not have the opportunity to appeal to regulators to recover costs associated with losing bids. More importantly, this concept violates the used and useful argument, and may create legal problems arising out of Oregon's "not presently used" statute. It is not clear how PGE thinks a non-winning bid can be found to be "used and useful" or "presently used."

Beyond the used and useful concerns, CUB has additional concerns about allowing costs associated with a failed bid to be placed into rates. Utilities are only allowed to place prudently-incurred costs into rates. Because the bid did not win the RFP, it seem likely that the RFP result would have been exactly the same without the Company's self-build proposal even being submitted, so the self-build proposal add costs but provide no benefit. How would a utility meet its burden of proof to show that costs associated with a losing bid were prudently incurred when the bid made no difference in the outcome of the RFP? How would the Commission evaluate the prudency of a bid?

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[30] UE 215 / PGE / 300 / Tooman – Tinker / 10.
[31] *Ibid*, page 11.

This proposal raises serious legal and policy concerns. PGE offers no forecast of the costs for 2011,[32] but is asking for changes so it can place these costs on customers. CUB believes that allowing costs associated with projects that are not built is poor public policy, and urges the Commission to reject this idea.

E. Expanding the AUT and PCAM.

In addition to proposing a number of new mechanisms to track costs between general rate cases, so risk is shifted from shareholders to customers, PGE is also proposing to expand its biggest existing tracker mechanism, the AUT/PCAM. PGE's proposal would add new costs to that tracker and take costs that have been considered operating costs and redefine them as power costs. There is an old saying that if you have a hammer, every problem looks like a nail. In PGE's case, if you have a power cost adjustment mechanism, every cost looks like a power cost.

PGE is proposing that certain costs that are not currently considered power costs be reclassified as power costs. This allows the Company to forecast the costs annually in the AUT and to use the PCAM to recover differences between actual costs and forecasts. The costs that PGE wishes to add, and the expected 2010 amounts are:

Mercury	$1.9 million[33]
Broker Fees	$0.7 million[34]
Collateral Deposits	$2.6 million[35]
Ammonia	$0.5 million[36]
Lime	$1.3 million[37]

[32] UE 215 / PGE / 300 / Tooman – Tinker / 13.
[33] UE 215 / PGE / 400/Niman – Peschka – Hager / 11
[34] Ibid., page 12.
[35] Ibid., page 13.
[36] Ibid., page 14-15.

CUB opposes these reclassifications and urges the Commission to reject AUT mission creep. The AUT, and its earlier version the RVM, were designed to update fuel and power costs. After the RVM was established it quickly devolved into an annual proceeding that considered changes to the power cost model and changes to the models used to develop the inputs for the power cost model. It was not longer a simple proceeding to update fuel and power costs. PGE renamed this mechanism the AUT and agreed to limit changes, including only allowing modeling changes in general rate cases.

While this docket is a general rate case and the Company is thus allowed to propose expanding the power cost adjustment mechanisms, CUB urges the Commission to reject this expansion. The cost items PGE is proposing to add are minor costs. The purpose of the RVM/AUT was to reforecast on an annual basis "significant" and "volatile" costs such as natural gas prices and wholesale market power prices. Using an old forecast for those costs could cause a utility to undercollect its power costs by tens of millions of dollars or more and thus such updates are "significant."

As noted, the costs that PGE is proposing to add here are small items for which PGE offers little evidence to suggest that they are subject to volatility. Because of their small size, these costs do not need to be reforecast each year. Rather than improving the ratemaking process, adding these items to the AUT would simply means that Staff and intervenors have more prices and more forecasts to examine each year in the AUT. Once again, what PGE is proposing would lead to more work for very little return. For this reason, CUB believes that these costs should continue to be forecast as operating costs in general rate cases.

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[37] Ibid, page 16.

IV. Used and Useful Rate Base.

PGE has a number of investments that are not expected to be used and useful when rates go into effect. PGE is proposing that it be allowed to forecast the cost and timing of these ratebase additions and add them to average rate base starting on January 1, 2011, to ensure that there is no regulatory lag in cost recovery.

A. There are several problems with this proposal.

PGE is forecasting significant ratebase increases. This is unusual. Large new ratebase additions are not traditionally allowed to be included in rates until they are completed audited and have been reviewed for prudency. This was the case for Coyote Springs, Port Westward, and the Selective Water Withdrawal Project, for example. Changing the protocol for ratebase additions raises several policy and legal issues (our legal concerns will be explained in more detail in CUB's Opening Brief).

i. Customers will be paying for these rate base additions before they are used and useful.

Independent from CUB's legal concerns is the policy issue of used and usefulness: charging customers for a cost that is not yet used and useful creates a mismatch of costs and benefits and places the financial risk for the project's completion onto customers. The rates set in this docket will go into effect months before these projects are in service and providing any benefit to customers.

ii. PGE does not have a good track record of major investments being completed on time.

The Port Westward generating facility, and the Selective Water Withdrawal project are simply the latest examples of PGE's history of project delays. PGE's proposal to be allowed to forecast major ratebase additions creates significant problems if those projects are later delayed. In the case of a project delay, customers will have paid more in ratebase than what is used to serve them. This would seem on its face to violate the used and useful principle. This is not a minor issue. Significant, large ratebase projects can be delayed by weeks or by months.

iii. If the project costs are less than PGE's projection, customers will be charged a higher rate base than is used to serve them.

PGE is forecasting the cost of these major new construction projects. But construction forecasts often include contingency budgets, and estimated costs. Until a project is completed and all costs are fully reconciled, the cost is simply a forecast. Allowing significant new ratebase costs to be placed on ratepayers bills based on a forecast is poor policy and would encourage utilities to overforecast the cost of construction projects and could lead to customers paying a higher rate base than is actually used to provide utility service to them.

B. Past approaches to solving this issue have been problematic.

i. CUB has advocated letting regulatory lag work.

In the past, CUB has argued that regulatory lag is a part of ratemaking and should be allowed on projects like this. Regulatory lag works both ways. During the 1990s, utilities went long periods between rate cases and between major new investments. Each year, ratebase declined as it was amortized, but rates were not reset and utilities overearned. Thus, regulatory lag has been harmful to customers in the past. Allowing regulatory lag when a major new investment is not completed in time for the rate period does not strike CUB as either unfair or unreasonable. CUB does recognize, however, that the

Commission has not historically adopted CUB's approach in regard to allowing regulatory lag for significant ratebase additions.

ii. Coyote Springs: Single Issue Rate Case

Another approach is to open a single issue rate case, such as the one that was used in docket UE 95 to evaluate PGE's investment in the Coyote Springs generating facility. There is no statutory basis for a single issue rate case, so while parties can agree to open one, the Commission must consider evidence to ensure that it is the proper approach to an issue. In the Coyote Springs example, CUB did not sign the stipulation that established the single issue rate case. Costs changed by the time Coyote Springs came on line, and CUB was able to make a strong case that the increase was not necessary. The Commission rejected CUB's case.[38] However, on reconsideration, the Commission agreed that the cost reductions were real and if they continued they needed to be passed through to customers.[39] This led to a rate case later in 1996 for the expressed purpose of reducing rates and passing though to customers the cost reductions that had been denied in UE 95.[40] In the end customers got a rate decrease in UE 100 that was larger than the rate increase in UE 95, highlighting the risk of single issue ratemaking.

iii. Port Westward: Mid-Year True-Up

In this case, the Commission approved the rate base before it was used and useful, but the Port Westward rates did not go into effect until after the facility became used and useful. There was also an updated review of PGE's costs to determine whether there were offsetting cost reductions from the forecast. This was a difficult process, and one that would not work well with multiple rate base additions because of the time involved in the

[38] OPUC Order No. 95-1216.
[39] OPUC Order No. 96-053.
[40] OPUC Order No. 96-306.

cost update/review. In order to maintain necessary protections for customers, this type of update has to happen quickly and within a full regulatory calendar; otherwise, it is not clear that a mid-year true-up can be accommodated.

iv. Deferrals might be a better alternative.

First, it is important to note that CUB continues to believe that regulatory lag is acceptable and that it is the appropriate solution in this case. CUB continues to think the Coyote Springs and Port Westward solutions do not work well. CUB offers up as an alternative, allowing a utility to defer the revenue requirement impact of the rate base. While CUB has been quite active in complaining about the overuse of deferrals, we have concluded that it might be an acceptable method here.

Deferrals have several advantages in this circumstance:

- Deferrals come with an earnings test, so there will be a review to ensure that there have not been cost reductions that would allow the utility to absorb the rate base without increasing rates.
- Deferrals are based on actual costs, so if the cost is below what is forecast, the utility would not be allowed to base its rates on the forecast.
- Deferrals have prudence reviews before they go into rates.
- The current deferral policy generally discourages deferrals for minor items.

CUB opposes PGE's request to forecast significant new ratebase items. The proposal raises serious legal and policy issues. CUB believes that allowing regulatory lag is not unreasonable. If the Commission is unwilling to do so, CUB believes that allowing PGE to defer the revenue requirement associated with these investments once they become used and useful might be reasonable.

V. Decoupling.

CUB is encouraged that the current economic downturn has not resulted in the significant decoupling charge that we were concerned might occur.

The PUC set out a list of questions that the Company was supposed to answer in an evaluation of decoupling.[41] These questions included:

[41] OPUC Order No 09-020.

- Did the decoupling mechanism effectively remove the relationship between the utility's sales and profits?

- Did the mechanism effectively mitigate the utility's disincentives to promote energy efficiency?

- Did the mechanism improve the utility's ability to recover its fixed costs?

- Did the mechanism reduce business and other financial risk? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.

- What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanism?

- To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in this proceeding?

PGE's Exhibit 1507 makes clear that it is too early to fully evaluate the decoupling mechanism, but proposes the continuation of decoupling, anyway. CUB is willing to support the continuation of decoupling pilot, but believes that one change in the mechanism is necessary, and that the mechanism should be reviewed after it has been in place for 5 years. The PUC required that NW Natural and Cascade Natural Gas employ an independent analyst to examine their decoupling mechanisms, and CUB believes that a similar approach is appropriate here.

PGE made one change to its decoupling proposal. The 2% annual cap has been changed from a soft cap to a hard cap. CUB supports this change, as 2% is more than enough to accommodate changes in load due to conservation and energy efficiency, which was the stated purpose of decoupling.

For residential customers, PGE's decoupling mechanism compares two figures: the amount of fixed costs (distribution, transmission and fixed generation) forecasted to be recovered from a customer at a rate of 5.8426 cents/kWh, with a monthly fixed cost forecasted to be $51.29/month per customer. This is an approximately $10 per month increase in monthly fixed costs.[42] Since residential load has held steady during this recession, this can be viewed as an approximate 25% increase in fixed cost revenue requirement being assigned to residential customers. PGE offers no explanation for this dramatic increase. CUB encourages PGE to explain the 25% increase in its rebuttal testimony.

The one change that CUB proposes to PGE's decoupling mechanism at this time results from the fact that the mechanism fails to recognize that while some costs are largely fixed, few of these costs are actually fixed on a per kilowatt-hour basis or on a dollars/customer-month basis. The goal, therefore, is not to recover 5.8 cents/kWh for fixed costs, or even $51.29/month, but to recover $615.48 (51.29 X 12) per year.

CUB believes that over time PGE's proposed method will overcollect fixed costs. To understand why, let's begin with PGE's variable costs. PGE has a number of generation facilities. Some have large variable costs such as coal and natural gas, while other facilities such as hydro and wind have little or no variable power costs. When PGE's power operations are attempting to meet load, the Company will begin by dispatching its lowest variable cost resources, and then moving up its resources stack to its highest price variable resources. This means that the first kilowatt hour a customer buys will have little or no variable power costs, and the last kilowatt hour bought will be the most expensive.

However, customers pay the same retail rate for cheap hydro power as they do for power from an expensive peaker plant. The difference is that the bulk of payment for hydropower goes to cover fixed costs, while the bulk of payment for peaker plants goes

[42] UE 197/Schedule 123.

to cover variable costs (primarily fuel). In other words, while some costs are fixed, collections for those costs are not fixed on a per-kilowatt hour basis. If a customer reduces demand by a kilowatt-hour of electricity, then PGE has to make a decision: 1) It can reduce generation from its most expensive operating resource (the last one in the current resource stack); 2) It can cut back on the power it is purchasing in the market; or 3) It can sell the kilowatt-hour it would have sold to the customer to the wholesale market.

This reduction of a single kilowatt-hour will reduce PGE's collection towards fixed costs, but not by 5.842 cents/kWh. Instead, it will reduce the contribution to fixed costs by the difference between the total retail rate and the variable cost of that marginal unit of power, because that difference represents the amount of the customer's payment that would be available for fixed cost recovery. In order to set a price for the cost of that marginal power, CUB recommends the following change. CUB recommends that power purchase costs be used instead. Wholesale power prices represent the short-term marginal cost. A utility can buy or sell into this market, so the market price represents the value of the power that the customer did not use. The difference between the retail rate and this market power price represents the contribution towards fixed costs that PGE would have gotten from that unit of power.

Because PGE updates its power costs as this case goes forward, CUB cannot say where the final short term marginal cost for power should be set. However, with market power prices depressed due to current economic conditions, we don't expect our proposal to change the mechanism dramatically in the near term. In the future, however, as market prices rise, CUB's approach will be necessary to prevent PGE from overcollecting on its fixed costs.

VI. Conclusion

In summary, CUB makes the following recommendations to the Commission:

- The PUC should reject PGE's attempt to rewrite the regulatory paradigm by shifting risk from shareholders to customers.

- The PUC should reject PGE's proposal to change the PCAM by reducing the deadband and eliminating the earnings band. The mechanism is working as it was designed to work.

- The PUC should reject PGE's proposal for a balancing account for Level III storm damage costs. PGE's mechanism would create significant work with little benefit.

- The PUC should reject PGE's proposal for a tracker for environmental clean-up costs. This proposal is premature because environmental clean-up costs have not risen to a level that requires a separate mechanism.

- The PUC should reject PGE's proposal for an accounting order which would allow PGE to recover costs associated with a self-build option that was not approved in an RFP. The costs PGE wants to charge to customers are not used and useful to providing utility service.

- The PUC should reject PGE's proposal to expand the AUT/PCAM by reclassifying operating costs as power costs. The costs PGE proposes to include in the AUT/PCAM are not significant and/or volatile enough to justify annual ratemaking treatment.

- The PUC should reject PGE's proposal to forecast significant new capital investments into rate base and begin charging customers for these investments before these investments are used and useful. This is a drastic change from current regulation and makes it likely customers will be charged for costs that are not used and useful.

- The PUC should authorize the continuation of PGE's decoupling pilot for three more years. However, the PUC should change the decoupling mechanism to prevent PGE from overcollecting fixed costs and the PUC should require a review of the mechanism after it has been in place for 5 years.

WITNESS QUALIFICATION STATEMENT

NAME:	Bob Jenks
EMPLOYER:	Citizens' Utility Board of Oregon
TITLE:	Executive Director
ADDRESS:	610 SW Broadway, Suite 308 Portland, OR 97205
EDUCATION:	Bachelor of Science, Economics Willamette University, Salem, OR
EXPERIENCE:	Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, and UM 1209. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates. Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.
MEMBERSHIP:	National Association of State Utility Consumer Advocates Board of Directors, Environment Oregon Research and Policy Center Telecommunications Policy Committee, Consumer Federation of America Electricity Policy Committee, Consumer Federation of America

Macquarie Capital (USA), Inc.

Global Infrastructure Conference
May 25-26, 2010

Portland General Electric

Cautionary Statement

Information Current as of May 4, 2010

Except as expressly noted, the information in this presentation is current as of May 4, 2010 — the date on which PGE filed its Quarterly Report on Form 10-Q for the three months ending March 31, 2010 — and should not be relied upon as being current as of any subsequent date. PGE undertakes no duty to update the presentation, except as may be required by law.

Forward-Looking Statements

This presentation contains statements that are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

Forward-looking statements include statements regarding earnings guidance; statements regarding future load, hydro conditions and operating and maintenance costs; statements regarding the future impact of SB 408; statements regarding future capital expenditures; statements regarding future financings and PGE's access to capital and cost of capital; statements regarding PGE's future liquidity; statements regarding the cost, completion and benefits of capital projects; statements regarding future generation and transmission projects, including those set forth in the Company's Integrated Resource Plan; statements concerning future operation of the Company's Boardman coal plant; statements concerning the outcome of the 2011 general rate case and the timing of a final order from the OPUC; statements regarding the outcome of any legal or regulatory proceeding; as well as other statements containing words such as "anticipates," "believes," "intends," "estimates," "promises," "expects," "should," "conditioned upon," and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including reductions in demand for electricity and the sale of excess energy during periods of low wholesale market prices; the outcome of the 2011 general rate case filing; regulatory approval and rate treatment of the smart meter project and Phase III of the Biglow Canyon Wind Farm project; operational risks relating to the Company's generation facilities, including hydro conditions, wind conditions, disruption of fuel supply, and unscheduled plant outages, which may result in unanticipated operating, maintenance and repair costs, as well as replacement power costs; the costs of compliance with environmental laws and regulations, including those that govern emissions from thermal power plants; changes in weather, hydroelectric and energy market conditions, which could affect the availability and cost of purchased power and fuel; changes in capital market conditions, which could affect the availability and cost of capital and result in delay or cancellation of capital projects; unforeseen problems or delays in completing capital projects, resulting in the failure to complete such projects on schedule or within budget; the outcome of various legal and regulatory proceedings; and general economic and financial market conditions. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this presentation are based on information available to the Company on the date hereof and such statements speak only as of the date hereof. The Company assumes no obligation to update any such forward-looking statements, except as required by law. Prospective investors should also review the risks and uncertainties listed in the Company's most recent Annual Report on Form 10-K and the Company's reports on Forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including Management's Discussion and Analysis of Financial Condition and Results of Operations and the risks described therein from time to time.

Portland General Electric

Portland General Investment Highlights

"Pure-play" electric utility

- Vertically integrated, regulated electric utility
- Attractive service territory and constructive regulatory dialogue
- Regulated ROE of 10.0%

Operational excellence

- Diversified, high-performing generation portfolio
- Well-managed power supply operations
- High quality, well-maintained T&D system
- Strong overall customer satisfaction

Low-risk growth plan

- Significant regulated capital investments as identified in Integrated Resource Plan drive rate base growth
- Natural gas generation and renewable resource investment opportunities
- Track record of completing projects on time and within budget

Prudent financial strategy

- Investment grade ratings of BBB / Baa2 (unsecured)
- Target capital structure: 50% debt, 50% equity
- Focus on maintaining a strong balance sheet and adequate levels of liquidity

Stability:

Dividend Yield

Attractive total return proposition

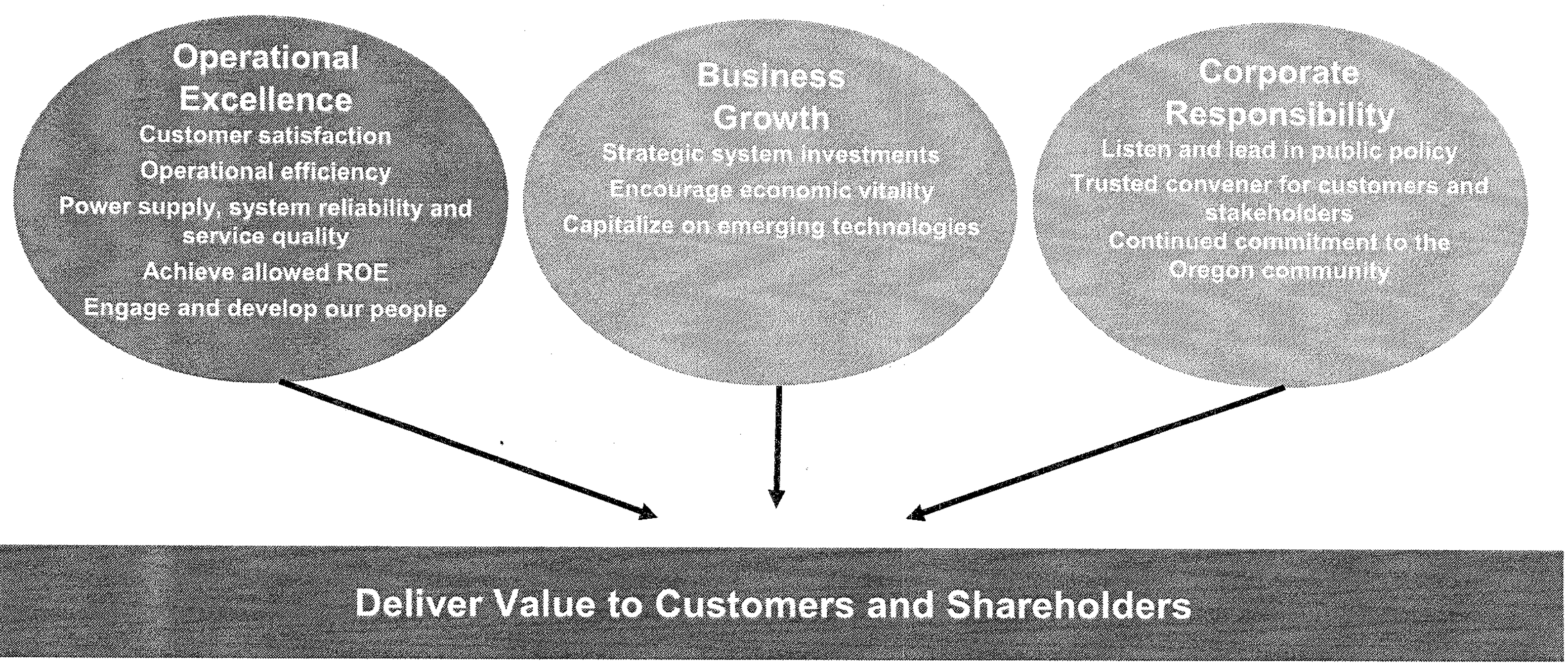
Growth:

Earnings Per Share

Portland General Electric

Portland General Strategic Direction

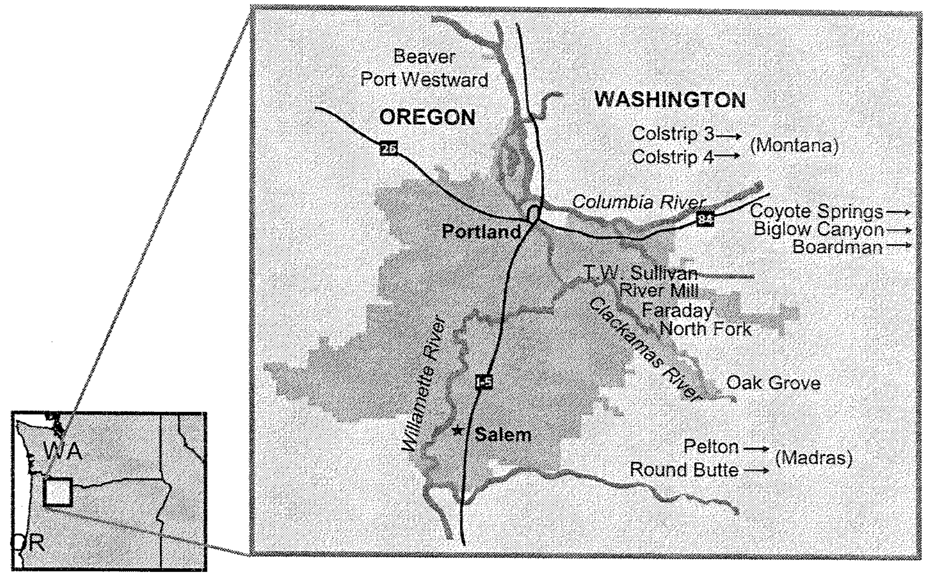
Mission: To be a company our customers and communities can depend upon to provide electric service in a safe, responsible and reliable manner, with excellent customer service, at a reasonable price.



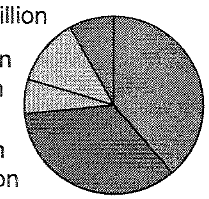
Portland General Electric

Attractive Regulated Business Profile

- Vertically integrated electric utility
  - Single-state jurisdiction
  - Virtually 100% regulated business
  - No holding company structure
- Attractive, compact service territory with 817,393 retail customer accounts(1)
- Opportunities for investment in core utility assets
- Diversified and growing customer base



Net Utility Plant



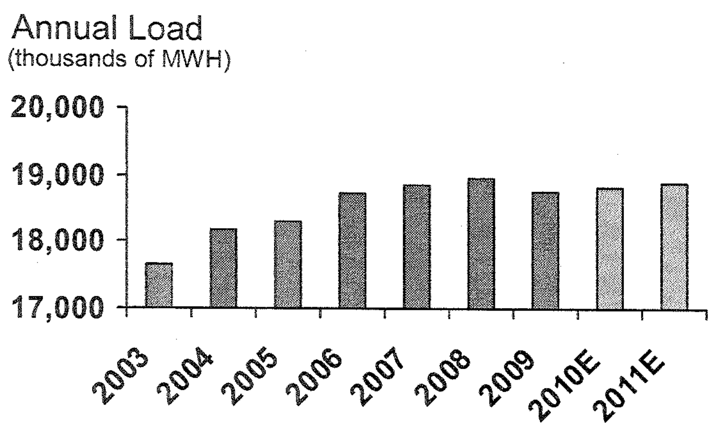
Net Utility Plant – $3,317 million(2)

(1) As of March 31, 2010.
(2) Source: 2009 FERC Form 1.

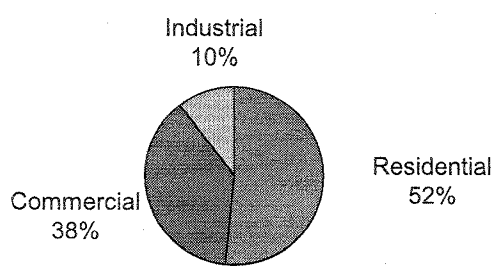
Portland General Electric

Attractive Service Territory

Weather Adjusted Annual Load (1)



2009 Retail Revenues by Customer Group (2)



Total = $1.6 Billion

- Compounded annual load growth(3) and customer growth of 1.0% from 2003 - 2009
  - Oregon is a leading in-migration state
- 2009 loads(3) declined 2.4% from 2008
  - Primary driver: Industrial declines in commodity and resource industries
- 2010 and 2011 loads(3) are forecast to be approximately flat compared to 2009
  - Expansion in high-tech partially off-set by declines in commodity and resources industries
  - Flat commercial sector with slight declines in residential loads
- Long-term annual load growth forecast of 1.9% through 2030

(1) Adjusted for weather and certain industrial customers.
(2) No single customer accounts for more than 1% of total retail revenues.
(3) Adjusted for weather.

Portland General Electric

Constructive Regulatory Environment

- **Oregon Public Utility Commission**
  - Governor-appointed Commission with staggered four-year terms
    (Ray Baum-Chair 8/2011, John Savage 3/2013, Susan Ackerman 3/2012[(1)])
- **Cost of Capital and Return on Equity**
  - 10.0% Allowed Return on Equity, 50% Debt, 50% Equity
- **Forward Test Year**
  - Filed General Rate Case on February 16, 2010 for 2011 test year
- **Net Variable Power Cost Recovery**
  - Annual Update Tariff [(2)]
  - Power Cost Adjustment Mechanism: contains deadbands and earnings test [(2)]
- **Decoupling**
  - Effective February 1, 2009 for two-year trial period [(2)]
- **Renewable Energy Standard**
  - Standard requires that PGE serve 25 percent of its retail load from renewable sources by 2025
- **Renewable Adjustment Clause (RAC)**
  - PGE can recover costs of renewable resources through a separate tracker
- **Integrated Resource Plan**
  - Acknowledgement standard
  - 2009 IRP - longer-term analysis to address resource decisions through 2020

(1) Susan Ackerman appointed to fill out remainder of Lee Beyer's term effective March 1, 2010
(2) See Appendix

Portland General Electric

Operational Excellence

Operational Efficiency

- Ongoing capital investments to improve quality of service, reduce costs and generate adequate shareholder return
- Smart Meter Program
  - Capex: $130-$135 million
  - Projected annual operational savings of $16.5 million

Customer Satisfaction

- Annual residential and general business customer satisfaction rankings are strong compared to the industry
- Ranked first in the nation for number of renewable power customers by the National Renewable Energy Laboratory

PGE

Well Maintained, High-Quality System

- PGE-owned generation assets were at 89 percent plant availability in 2009
- On-going infrastructure investments
  - Invested more than $775 million in transmission, distribution, and existing generation during the last 5 years

Portland General Electric

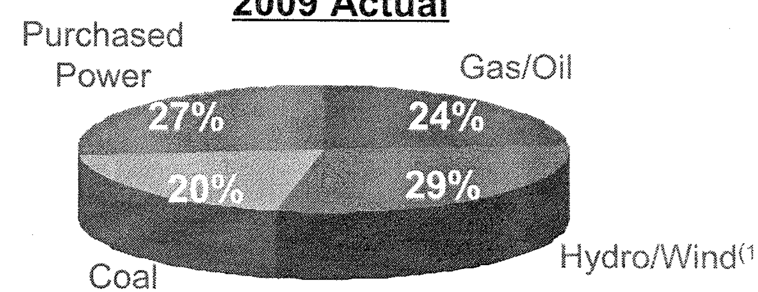
Operational Excellence

Average Resource Capacity (at 12/31/09)

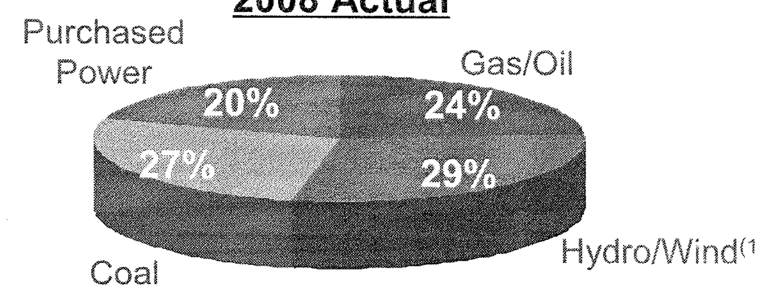
	Physical Capacity	% of Total Capacity
Hydro		
Deschutes River Projects	298 MW	6.6%
Clackamas/Willamette River Projects	191	4.2
Hydro Contracts	698	15.4
	1,187	26.2
Natural Gas/Oil		
Beaver Units 1-8	529 MW	11.7%
Coyote Springs	233	5.1
Port Westward	413	9.1
	1,175	25.9
Coal		
Boardman	374 MW	8.3%
Colstrip	296	6.5
	670	14.8
Wind(2)		
Wind Contracts	35 MW	0.8%
Biglow Canyon Phase I & II	100	2.2
	135	3.0
Net Purchased Power		
Short-/Long-term	1,363 MW	30.1%
Total	**4,530 MW**	**100.0%**

Power Sources as % of Retail Load

2009 Actual



2008 Actual

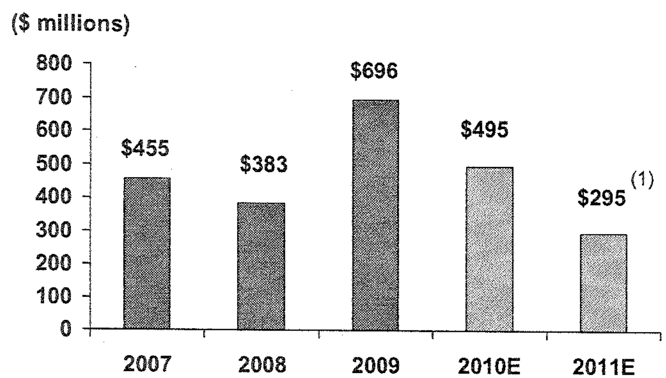


(1) Includes PGE owned and purchased hydro resources and PGE owned and purchased wind resources.
(2) Physical capacity for wind resources provided in average megawatts.

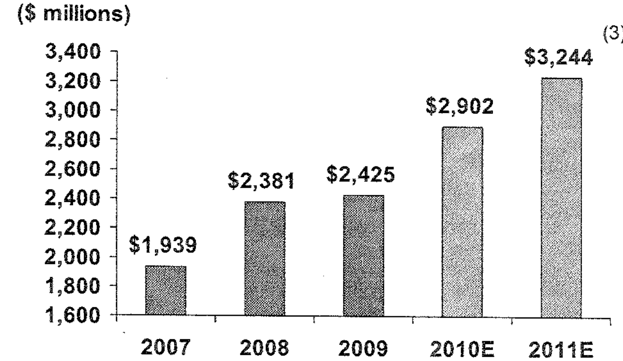
Portland General Electric

Business Growth

Capital Expenditures



Rate Base (Average) (2)



- Attractive, near-term regulated growth opportunities through capital investment focused on renewable resources and core utility assets
- 2010 capital investments funded through cash from operations and new debt issuances. Significant new capital investments beyond 2010 funded through cash from operations and issuances of debt and equity with a targeted capital structure of 50/50

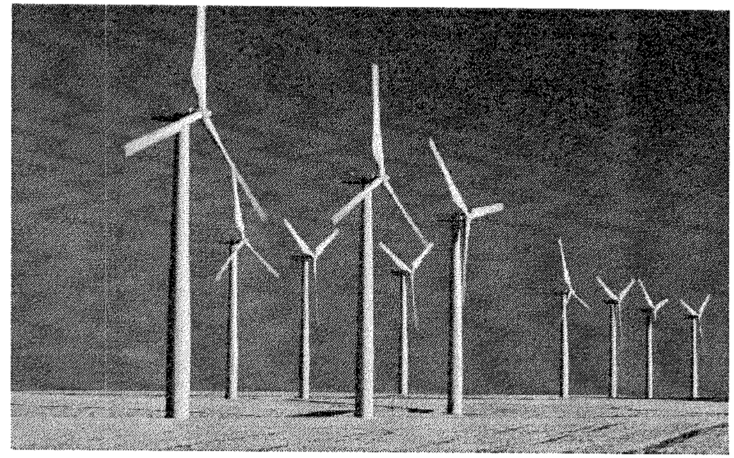
(1) 2011E capital expenditures does not include potential additional IRP self-build options and assumes Boardman 2020 plan.
(2) 2007 and 2008 average rate base as filed in the OPUC regulatory Results of Operations Report. 2009 average rate base includes the 2009 General Rate Case average rate base of $2.278 billion plus Biglow Canyon Phase II, and Smart Metering Project. 2010E average rate base includes 2009 General Rate Case average rate base of $2.278 billion plus Biglow Canyon Phase II & III, Smart Metering Project and the Selective Water Withdrawal project.
(3) 2011E average rate base per Exhibit 309 in 2011 General Rate Case

Portland General Electric

Business Growth

Biglow Canyon Wind Farm

- Columbia Gorge, eastern Oregon
- 450 MW total installed capacity
- Total cost approximately $1 billion
- Completion of Biglow Canyon Phase III will bring PGE's load served by renewables to approximately 11 percent (1)



	Phase I	Phase II	Phase III
Nameplate Capacity	125 MW, 76 turbines	150 MW, 65 turbines	175 MW, 76 turbines
MW per unit	1.65 Megawatts	2.3 Megawatts	2.3 Megawatts
Cost (w/AFDC)	$255 million	$321 million	$390 million
Online date	December 2007	August of 2009	Third Quarter of 2010
Vendor	Vestas	Siemens	Siemens

(1) As defined by Oregon's Renewable Energy Standard

Portland General Electric

Business Growth

- General rate case filed in February 2010 based on a 2011 test year
  - 2011 average rate base of $3.2 billion
  - 10.5% requested ROE based on a 50/50 capital structure
- Proposed revenue increase of $125 million for a 7.4% rate increase driven primarily by:

Driver/Cost	Revenue Increase
Investment and Related Costs (1)	4.3%
Higher O&M Costs (2)	5.1%
Power Cost Recovery	(2.0)%

1) Includes Biglow Canyon Phase III, Clackamas River Relicensing and other investment related costs. Also includes the increase in ROE from 10.0% to 10.5% which represents a 0.75% revenue increase
2) Includes impact of negative load growth from loads used to set current rates (2009 test year)

Portland General Electric

Business Growth: General Rate Case (cont'd)

Policy Objective Proposals

Power Cost Adjustment Mechanism:

- Deadbands narrowed and made symmetrical at a fixed amount of $10 million
- 90/10 sharing outside of deadbands continued
- Earnings test deadbands eliminated

Boardman Automatic Adjustment Clause

- PGE allowed to change prices to reflect an OPUC – determined operating life
- Base case assumption is plant operating through 2040

Decoupling

- Continue with current mechanism

Key Proposed Accounting Orders

- Major storm damage recovery
- Pension automatic adjustment clause
- Environmental mitigation & remediation expense recovery
- Collateral cost recovery for power supply operation

Portland General Electric

Business Growth: General Rate Case (cont'd)

Schedule

- Process expected to take 10 months, with new prices proposed to be effective January 1, 2011
- General Rate Case filing available at **www.PortlandGeneral.com** (1)

Timing: 2010 (2)

February	June	July	August	September	Oct/Nov	December	January 2011
Case Filed	Staff and Intervener Reply Testimony	POR Rebuttal Testimony	Staff and Intervener Surrebuttal Testimony	POR Sursurrebuttal Testimony	Hearings and Briefs	Commission Decision	Prices Effective

(1) Follow these steps - Our Company, Corporate Information, Regulatory Documents, Filings, Docketed Filings, UE-215
(2) Represents approximate timeline

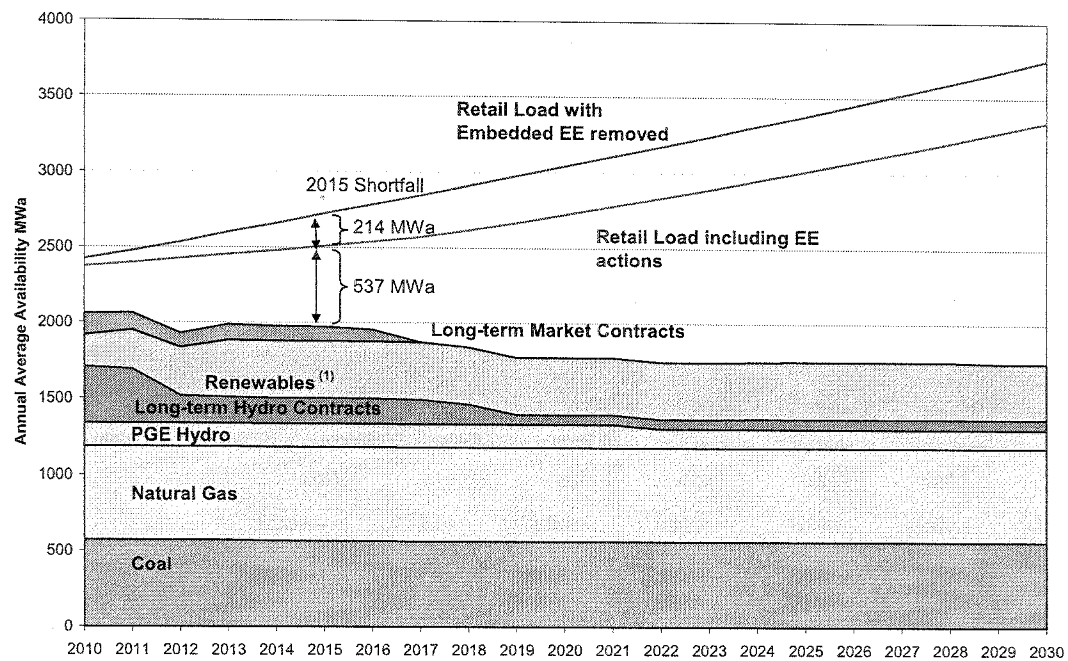
Portland General Electric

Business Growth

Load Growth

PGE's long-term retail load is expected to grow consistently while certain long-term power purchase contracts expire, driving the need for additional generation capacity

Load/Resource Forecast (2)



- **In 2015 we project a capacity shortfall of 1,724 MW**

Note: Assumes 1.9% load growth through 2030 and energy supply based on plant capabilities under normal hydro and operating conditions.
(1) Includes 122 MWa needed to meet 2015 Renewable Portfolio Standard
(2) Load/Resource Forecast Data from 2009 Integrated Resource Plan.

Portland General Electric

Business Growth

Integrated Resource Planning Process

- Under OPUC guidelines, PGE is required to file an Integrated Resource Plan (IRP) within two years of acknowledgment of the previous plan.
- The IRP requires that the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
- Goal is Commission acknowledgement of the IRP Action Plan. Acknowledgement is not approval for ratemaking purposes but the Commission has stated that it will give "considerable weight" to utility actions that are consistent with the acknowledged IRP.
- This is an open public planning process.

Schedule:

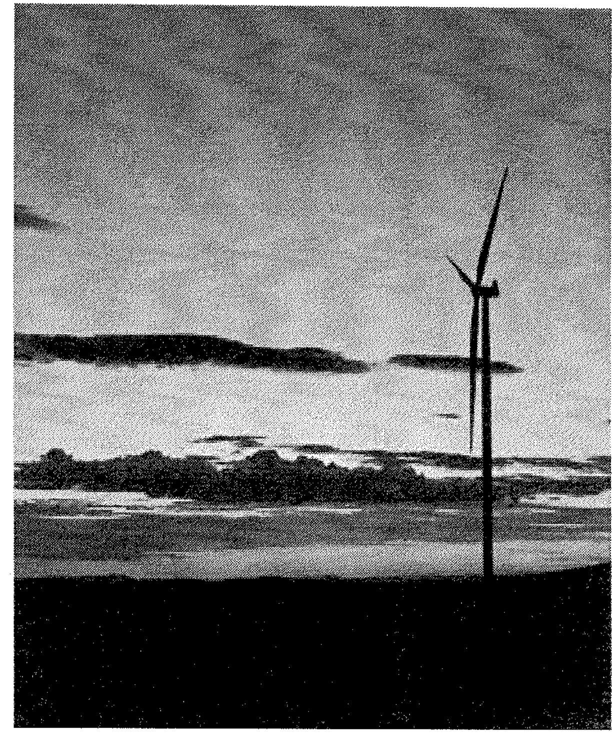
- November 2009: Plan filed
- April 2010: Filed addendum proposing 2020 alternative plan for Boardman
- Second Half 2010: OPUC order expected on the IRP

Portland General Electric

Business Growth

2009 Integrated Resource Plan (IRP) includes:

- **A long-term analysis of resource requirements to serve customers**
- **Expected resource requirements to include expansion of energy efficiency, additional renewable resources, purchase power agreements and new facilities to meet energy and capacity needs.**
- **Potential Capital Projects :**
  - **New energy resources** (1)
    - 300 – 500 MW natural gas facility (approximate capital cost \$1,300 - \$1, 400/kw)
      - Earliest date available - 2015
    - 122 MWa of renewable resources (2) (approximate capital cost \$2,200 - \$4,100/kw)
      - Earliest date available 2012
  - **New capacity resources** (1)
    - Up to 200 MW natural gas facility (approximate capital cost \$1,100 - \$1,400/kw)
      - Earliest date available 2013
  - **Emissions controls at Boardman Coal Plant** (3)
    - Oregon Environmental Quality Control adopted a rule requiring installation of emissions controls in three phases (2011-2017) with the plant operating through 2040 (approximate capital cost \$520-\$560 million)
    - PGE is pursuing an alternative 2020 plan
  - **Transmission**
    - **Cascade Crossing – 200 mile, 500-kV transmission line**
      - Approximate capital cost \$610 million for single circuit line
      - Approximate capital cost \$825 million for double circuit line
      - Completed by 2015



(1) PGE will conduct separate RFPs for the baseload energy resource, renewable resource and capacity resource, and will bid into each RFP with its own benchmark resource.
(2) Needed to physically meet Oregon's Renewable Energy Standard of 15% renewables by 2015
(3) See pages 34 & 35 in the appendix for additional detail

Portland General Electric

Prudent Financial Strategy

Target Capital Structure 50% Debt, 50% Equity

2010

Debt Issuance

- PGE anticipates issuing approximately $250 million in 2010
  - Issued $70 million of First Mortgage Bonds (FMBs) in January at 3.46%
  - Issued $121 million of Pollution Control Bonds backed by FMBs in March at 5.00%
  - PGE plans on issuing the remaining $59 million of the $250 million in long-term debt in Q2
- Issuance proceeds to fund:
  - 2010 FMBs maturities of $186 million
  - Biglow Canyon Phase III
  - Other capital projects

Equity Issuance

- Additional equity issuance is not expected until after 2010. When issuing equity a number of factors, come into consideration, including, items such as cash flow, capital requirements and market conditions

2009

Debt Issuance

- Issued $130 million of FMBs in January
  - $63 million at 6.50%
  - $67 million at 6.80%
- Issued $300 million of FMBs in April at 6.10%
- Issued $150 million of FMBs in November at 5.43%

Equity Issuance

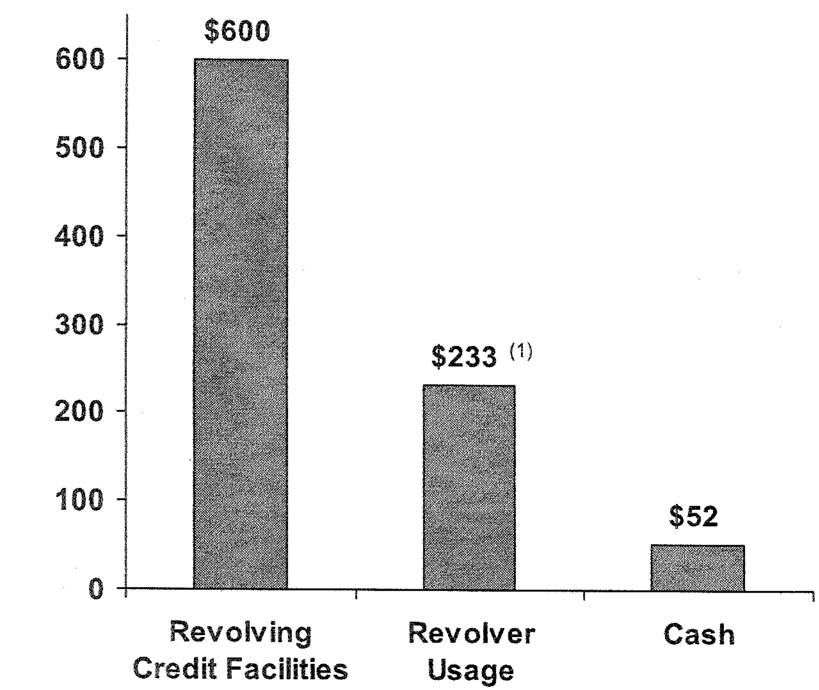
- Issued 12.5 million shares of common stock in March 2009 for net proceeds of $170 million

Portland General Electric

Prudent Financial Strategy

Liquidity (as of 03/31/10)

($ millions)



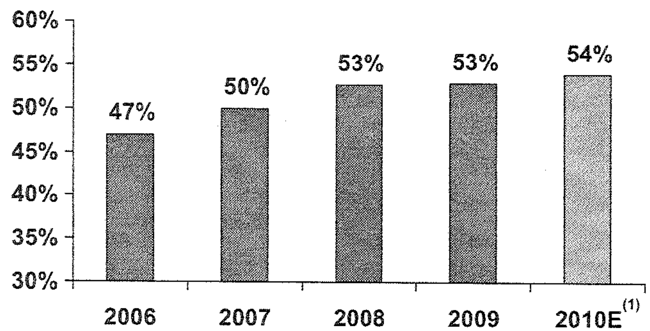
- $370 million revolving credit facility
  - $360 million matures in July 2013
  - $10 million matures in July 2012
- $30 million revolving credit facility matures in June 2012
- $200 million revolving credit facility matures in December 2012
- Margin deposits posted by PGE as of March 31, 2010 were $302 million [2]
  - Margin deposits create a cash flow timing difference but have minimal impact on earnings
  - Margin roll-off[3]
    - Approximately 42% in 2010
      - $109 million letters of credit
      - $18 million cash
    - Approximately 39% in 2011
      - $71 million letters of credit
      - $46 million cash

(1) Represents 100% letters of credit. On March 31, 2010, there were no draws on the revolver and no outstanding commercial paper.
(2) Consists of $89 million in cash and $213 million in letters of credit.
(3) Assumes market prices remain unchanged from March 31, 2010.

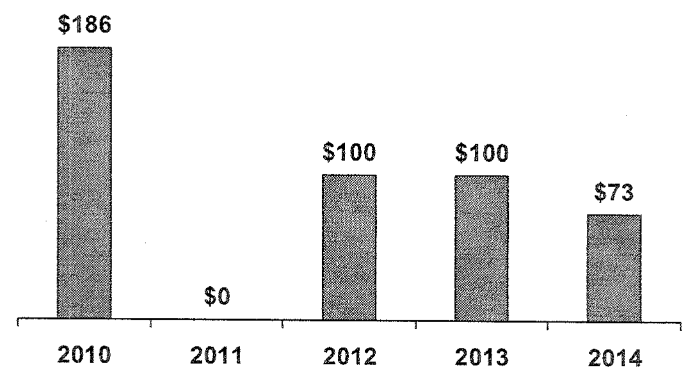
Portland General Electric

Prudent Financial Strategy

Debt/Capitalization



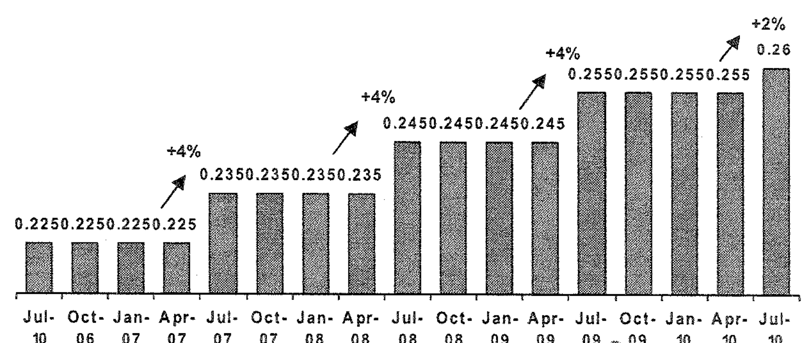
Manageable Near-term Debt Maturities



Credit Ratings

	Senior Secured	Senior Unsecured	Outlook
S&P	A-	BBB	Stable
Moody's	A3	Baa2	Positive

Dividend Growth [2]



(1) Includes $250 million of debt issuance in 2010
(2) Dividend as of payable date

Portland General Electric

Portland General Investment Highlights

- "Pure-play" electric utility
- Operational excellence
- Low-risk growth plan
- Prudent financial strategy

Stability:

Dividend Yield

Attractive total return proposition

Growth:

Earnings Per Share

Portland General Electric

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Portland General Electric

Appendix

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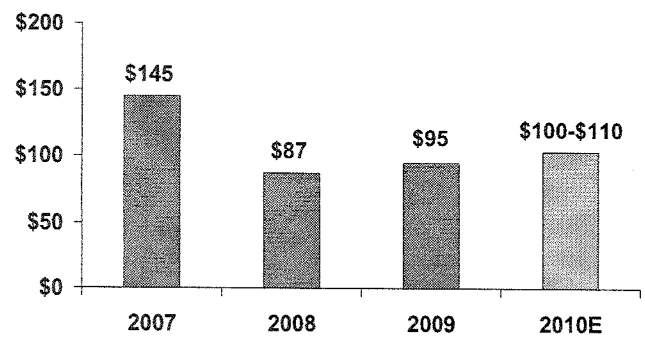
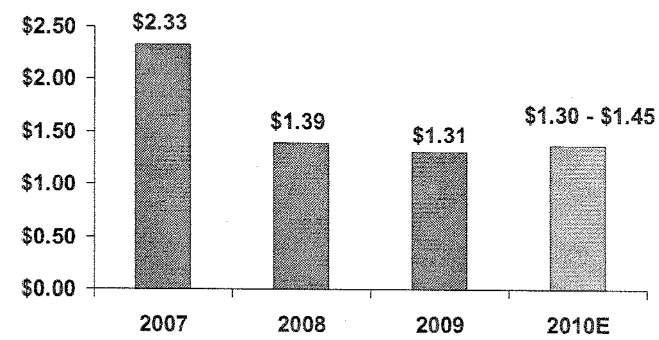
Portland General Electric

Recent Financial Results

Net Income



Earnings per Share (diluted)



Key Items ($ earnings per diluted share)

2007
- Boardman deferral (+$0.26)
- California settlement (+$0.06)
- Non-qualified benefit plan assets (+.05)
- Senate Bill 408 (+$0.18)

2008
- Trojan Refund Order Provision (-$0.32)
- Non-qualified benefit plan assets (-$0.19)
- Beaver oil sale (+$0.10)
- Senate Bill 408 (-$0.10)

2009
- Boardman Deferral (-$0.15)
- Selective Water Withdrawal (-$0.05)
- Non-qualified benefit plan assets (+$0.07)
- Senate Bill 408 (-$0.11)

2010
- As of May 4, 2010, earnings guidance was reaffirmed at $1.30 to $1.45 per diluted share.

Portland General Electric

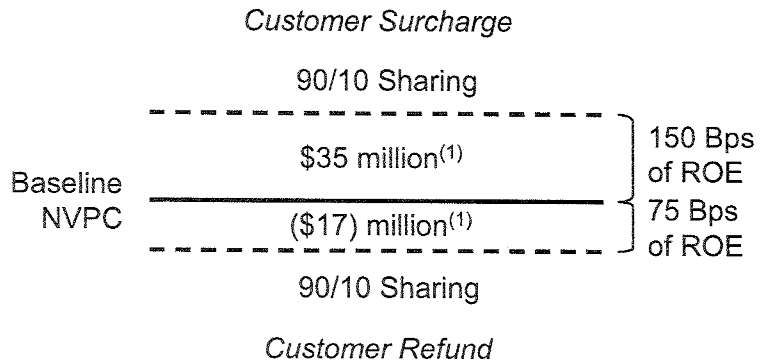
Recovery of Power Costs

Annual Power Cost Update Tariff

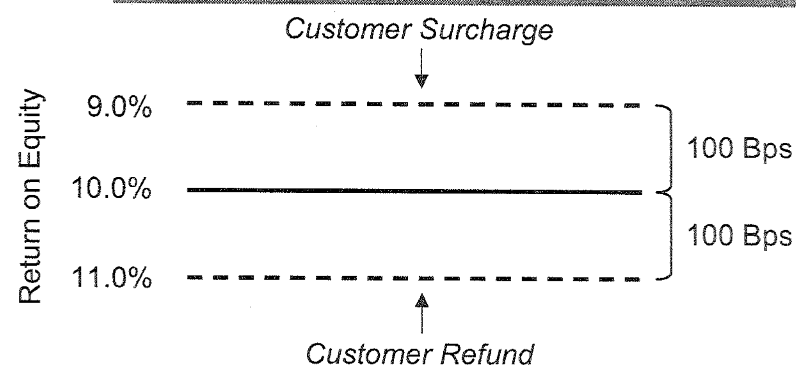
- Annual reset of rates based on forecast of net variable power costs (NVPC) for the coming year. Following OPUC approval, new prices go into effect on or around January 1 of the following year.

Power Cost Adjustment Mechanism (PCAM)

Power Cost Sharing



Earnings Test



- PGE absorbs 100% of the costs/benefits within the deadband, and amounts above or below the deadband are shared 90% with customers and 10% with PGE.
- An annual earnings test is applied as part of the PCAM.
  - Customer surcharge occurs to the extent it results in PGE's actual ROE being no greater than 9.0%
  - Customer refund occurs to the extent it results in PGE's actual ROE being no less than 11.0%

(1) Deadband for 2010 is $35 million above and $17 million below baseline net variable power costs

Portland General Electric

Decoupling Mechanism

- The decoupling mechanism is intended to allow recovery of reduced revenues resulting from a reduction in sales of electricity resulting from customers' energy efficiency and conservation efforts
  - A condition of the decoupling mechanism is a reduction in the Company's allowed ROE from 10.1% to 10.0% which reflects the OPUC's view of a reduction in Company risk. The ROE refund is estimated at approximately $1.9 million annually
- Implemented under a new two-year tariff that includes a Sales Normalization Adjustment mechanism (SNA) for residential and small non-residential customers (≤ 30 kW) and a Lost Revenue Recovery mechanism (LRR), for large non-residential customers (between 31 kW and 1 MWa)
  - The SNA is based on the difference between actual, weather-adjusted usage per customer and that projected in PGE's recent general rate case. The SNA mechanism covers approximately 57% of base revenues
  - The LRR is based on the difference between actual energy-efficiency savings (as reported by the ETO) and those incorporated in the applicable load forecast. The LRR mechanism covers approximately 20% of base revenues
- On January 31, 2009, PGE filed an application with the OPUC to defer, for later rate-making treatment, potential revenues associated with the new decoupling mechanism as well as revenues associated with an ROE refund
- Mechanism effective February 1, 2009
- Estimated customer refund for 2009: $6.8 million (1)
- Estimated customer collection through Q1 2010: $5.1 million (1)

($'s in millions)	Q1	Q2	Q3	Q4	YTD 2010
Sales Normalization Adjustment (1)	$5.6				$5.6
ROE Adjustment	($0.5)				($0.5)
Lost Revenue Adjustment	$0.0				$0.0
Total adjustment	$5.1	$0.0	$0.0	$0.0	$5.1

Note: positive = customer collection negative = customer refund

(1) Subjected to review and approval by the OPUC

Portland General Electric

Decoupling Mechanism

Simplified Decoupling Example

Assumptions:

- Residential customer
- Monthly Kwh usage: 1,000
- Cost per Kwh: $0.10
- Weather adjusted decrease in monthly usage: 10%
- PGE cost structure: 50% power costs and 50% all other costs

Analysis:

Base monthly bill:	1,000 x $0.10 = $100
Revised monthly bill due to energy efficiency and/or conservation:	900 x $0.10 = $ 90
Reduction in revenue from customer	= $ 10

PGE cost structure of lost revenue:

- $5 in power costs
- $5 in all other costs (fixed costs)

Financial impact on PGE:

- Power costs: Approximately $0 earnings impact on PGE, assuming power sold on the market at PGE average cost in prices
- All other costs: Approximately $0 earnings impact due to $5 booked as a regulatory asset for future recovery from customers (**through the decoupling mechanism**)

Portland General Electric

Oregon Senate Bill 408

- Beginning January 1, 2006, SB 408 requires the OPUC to track estimated income taxes collected by Oregon utilities in rates and compare this amount to adjusted taxes paid to taxing authorities by the utility or corporate consolidated group. The OPUC may establish deferral accounts to capture the difference.
- SB 408 requires an annual rate adjustment if difference between taxes authorized to be collected by the utility and taxes paid by the utility to taxing authorities exceed $100,000.
- Report for prior calendar year is filed in October with the refund or collection beginning in June of the following year.
- Primary issue for PGE is the so called "double whammy" effect, due to the OPUC adopting a fixed reference point for margins and effective tax rates. The double whammy can result in unusual outcomes and increased financial volatility in certain situations. The OPUC stated in the final order that it will be responsive to concerns related to the consequences of the double whammy problem, and may address those concerns in other regulatory proceedings.
- Historical/expected outcomes:
  - 2006: Customer refund of approximately $37.2 million plus accrued interest
  - 2007: Customer collection of $14.7 million plus accrued interest
  - 2008: Customer refund of approximately $10 million plus accrued interest
  - 2009: Customer refund of approximately $13 million plus accrued interest
- Protection of federal tax normalization rules is a key element of SB 408. As a result of significant accelerated tax depreciation in 2010, the protection of normalization will come into effect. Thus, no material collection or refund is expected in 2010.

Portland General Electric

Energy Action Plan

2009 Integrated Resource Plan – Energy

Energy Action Plan in MWa (1)(2)

	2015
Thermal Resource Actions	
Combined Cycle Combustion Turbine	406
Combined Heat & Power	2
Boardman Lease Contract	-
Renewable & EE Resource Actions	
ETO Energy Savings Trust	214
Existing Contract Renewals	66
RPS Compliance	122
Biomass	-
Geothermal	-
Solar PV	-
To Hedge Load Variability	
Short and Mid-term Market Purchases	100
Subtotal (3)	909
(Surplus) / deficit met by market	(36)
Total Resource Actions	**873**

(1) Data from Integrated Resource Plan Addendum filed in April 2010.
(2) Assumes normal hydro.
(3) Total does not foot due to rounding

Portland General Electric

Capacity Action Plan

2009 Integrated Resource Plan – Capacity

Capacity Action Plan in MW (1)(2)(3)

	Winter
	2015
Thermal Resource Actions	
Combined Cycle Combustion Turbine	441
Combined Heat & Power	2
Boardman Lease Contract	-
Renewable & EE Resource Actions	
Existing Contract Renewals	167
RPS Compliance	18
Biomass	-
Geothermal	-
Solar PV	-
To Hedge Load Variability	
Short and Mid-term Market Purchases	100
Capacity Only Variability	
Flexible Peaking Supply	200
Customer-Based Solutions (Capacity Only)	
Dispatchable Standby Generation	67
Demand Response	60
Seasonally Targeted Resources	
ETO Capacity Savings Target	315
Bi-seasonal Capacity	202
Winter-only Capacity	152
Total Incremental Resources	1,724

(1) Data from Integrated Resource Plan Addendum filed in April 2010.
(2) Assumes normal hydro.
(3) Based on winter peak. Summer peak is 1,468 MW for 2015.

Portland General Electric

Renewable Energy Standard

Additional Renewable Resources

- Integrated Resource Plan addresses 122 MWa of wind or other renewable resources necessary to meet requirements of Oregon's Renewable Energy Standard by 2015

Renewable Energy Standard

- Renewable resources can be tracked into rates, through an automatic adjustment clause, without a general rate case. A filing must be made to the OPUC by the sooner of the on-line date or April 1st in order to be included in rates the following January 1st. Costs are deferred from the on-line date until inclusion in rates and are then recovered through an amortization methodology.

Year	Renewable Target
2011	5%
2015	15%
2020	20%
2025	25%

- Biglow Canyon Wind Farm will bring PGE's load served by renewables to approximately 11 percent by the end of 2010

Portland General Electric

Estimated RPS Position by Year (1)

- **PGE will be in compliance with 2015 renewable resource requirement with addition on 122 MWa of renewables resources**

	2011	2015	2020	2025
Calculate Renewable Resource Requirement:				
PGE retail bus bar load	2,442	2,624	2,886	3,179
Remove incremental EE	(16)	(86)	(135)	(135)
Remove Schedule 483 5-yr. load	(27)	(28)	(28)	(28)
A) Net PGE load	2,399	2,510	2,723	3,016
Renewable resources target load %	5%	15%	20%	25%
B) Renewable Resources Requirement	120	376	545	754
Existing renewable resources at Bus:				
Vansycle Ridge	8	8	8	8
Klondike II	26	26	26	26
Klondike II dedicated to PGE green tariff	-5	0	0	0
Sale of RECs	0	0	0	0
Biglow Canyon Phase I (year-end 2007)	48	48	48	48
Biglow Canyon Phases II and III (year-end 2008, 2010)	114	114	114	114
Post-1999 Hydro Upgrades	9	9	9	9
Pelton Round Butte LIHI Certification	50	50	50	50
C) Total Qualifying Renewable Resources	250	255	255	255
Compliance position & RECs banking:				
D) Excess/(deficit) RECs B4 new IRP Actions (C less B)	130	(122)	(290)	(499)
E) IRP Action Plan* - additional resources for 2015 compliance	0	122	122	122
F) Total PGE renewable resources (C plus E)	250	377	377	377
G) % of load served via RPS renewables (F divided by A)	10.4%	15.0%	13.9%	12.5%
H) Excess/(deficit) RECs after IRP Actions (D plus E)	130	-	(168)	(377)
I) Cumulative Banked RECs after IRP Actions	**709**	**1,408**	**1,185**	**200**
J) Cummulative Non-LIH Banked RECs after IRP Actions	**509**	**1,208**	**985**	**-180**
** Previously approved action from the 2007 IRP*				

(1) In MWa; Chart disclosed in Integrated Resource Plan filed in November 2009

Portland General Electric

Smart Grid

Smart Meters

- Provides two-way communications with residential and commercial customers
- Vendor: Sensus Metering Systems
- Technology: FlexNet radio frequency technology
- Deployment: 850,000 residential and commercial customer meters
- Installed approximately 646,000 meters as of April 13, 2010 with estimated completion by the end of 2010
- Estimated cost: $130 million - $135 million
- OPUC approved limited term tariff: June 1, 2008 through December 31, 2010. After 2010 the project costs, net of savings, would be permanently incorporated into rates in a future rate case

- **Distribution System**
  - Pursuing direct load control programs
  - Optimizing distribution system through advanced technology

Portland General Electric

Boardman Coal Plant: 2020 Plan

- PGE has filed an addendum to its 2009 Integrated Resource Plan (IRP) seeking acknowledgment of a plan to cease coal fired operation at Boardman in 2020, subject to the following three conditions:
  - Oregon Environmental Quality Commission (OEQC) must approve a revised Regional Haze rule consistent with PGE's 2020 closure plan under which PGE would:
    - Install low NOx burners and modified over-fired air by July 2011 with an estimated cost of $28 million (1)
    - Use a lower sulfur coal
    - Cease coal fired operations in 2020
  - PGE must have reasonable assurance that its 2020 closure plan will be compliant with forthcoming federal clean air standards
  - Resolution of pending litigation concerning Boardman operations must be consistent with the 2020 closure plan
- The IRP addendum requests OPUC acknowledgement to proceed with installation of all required emissions controls (see slide 35) and operating Boardman through at least 2040 if any of the above three conditions is not met by March 31, 2011
- Decision from the OPUC expected in the second half of 2010
- PGE is working with all stakeholders on acceptance and approval of the alternative 2020 plan

(1) Under a separate rule PGE plans on installing mercury controls by 2011 with an estimated cost of $8 million

Portland General Electric

Boardman Coal Plant: 2040 Contingent Plan

- **If the contingencies for PGE's 2020 closure plan are not resolved, PGE's 2009 IRP proposes the continued operation of Boardman through 2040 with the addition of controls called for in the OEQC rule. This recommendation is based upon the expected cost and risks relating to carbon dioxide emissions, replacement generation, coal and natural gas, and emissions controls required to meet the OEQC's rule.**

- **In June 2009, the OEQC adopted a rule that would require the installation of emissions controls at Boardman under a phased-in approach:**
  - Phase 1: Installation of low NOx burners and modified over-fire air with estimated completion by July 2011 with a total cost of $28 million(1)
  - Phase 2: Installation of semi-dry scrubber and bag house to address mercury and sulfur dioxide removal with estimated completion by July 2014 with a total cost of approximately $290 million
  - Phase 3: Installation of Selective Catalytic Reduction for additional NOx controls with estimated completion by July 2017 with a total cost of approximately $180-$200 million
  - Phases 1 and 2 would meet federal Best Available Retrofit Technology (BART) requirements. Phase 3 would meet the requirements to make reasonable progress towards haze emission reduction goals.

- **Decision from the OPUC expected in the second half of 2010**

(1) Under a separate rule PGE plans on installing mercury controls by 2011 with an estimated cost of $8 million
NOTE: Estimated costs above reflect 100% of total costs, excluding AFDC

Portland General Electric

Portland General
Electric

Portland General
Electric

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aeo2010r.d111809a **2007** **2008** **2009** **2010**

Report	Annual Energy Outlook 2010
Scenario	aeo2010r
Datekey	d111809a
Release Date	December 2009

Table 8. Electricity Supply, Disposition, Prices, and Emissions
(billion kilowatthours, unless otherwise noted)

Supply, Disposition, and Prices	**2007**	**2008**	**2009**	**2010**
Prices by Service Category				
(2008 cents per kilowatthour)				
Generation	6.2	6.7	6.5	5.9
Transmission	0.7	0.7	0.7	0.8
Distribution	2.4	2.4	2.4	2.5
(nominal cents per kilowatthour)				
Generation	6.0	6.7	6.6	6.1
Transmission	0.7	0.7	0.7	0.8
Distribution	2.4	2.4	2.4	2.5
Electric Power Sector Emissions 1/				
Sulfur Dioxide (million tons)	8.93	7.61	6.39	5.71
Nitrogen Oxide (million tons)	3.29	3.00	2.42	2.25
Mercury (tons)	47.02	45.84	42.38	40.59

1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to
2/ Includes plants that only produce electricity.
3/ Includes electricity generation from fuel cells.
4/ Includes non-biogenic municipal waste. The Energy Information Administration estimates that in 2008 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy, (Washington, DC, May 2007).
5/ Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, ar
6/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
7/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
8/ Includes refinery gas and still gas.
9/ Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and win
10/ Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
11/ Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 and 2008 are model results and may dif
Sources: 2007 and 2008 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Infor
Annual Energy Review 2008, DOE/EIA-0384(2008) (Washington, DC, June 2009) and supporting databases.
2007 and 2008 prices: EIA, AEO2010 National Energy Modeling System run aeo2010r.d111809a.
Projections: EIA, AEO2010 National Energy Modeling System run aeo2010r.d111809a.

2011	2012	2013	2014	2015	2016	2017	2018	2019

Reference case

2011	2012	2013	2014	2015	2016	2017	2018	2019
5.4	5.7	5.7	5.5	5.5	5.6	5.7	5.7	5.7
0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9
2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
5.6	6.0	6.1	6.1	6.2	6.4	6.6	6.7	6.8
0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
2.6	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0
5.36	5.31	5.21	5.02	4.69	4.47	4.38	4.37	4.31
2.25	2.27	2.25	2.24	2.05	2.02	2.01	2.01	2.02
41.82	42.31	42.89	42.69	30.48	30.75	30.11	30.24	30.33

the public.

ıd wind power.

d power.

ïfer slightly from official EIA data reports.
rmation Administration (EIA),

2020	2021	2022	2023	2024	2025	2026	2027	2028

2020	2021	2022	2023	2024	2025	2026	2027	2028
5.8	5.8	5.9	6.0	6.1	6.1	6.1	6.2	6.3
0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4
7.1	7.3	7.5	7.8	8.1	8.2	8.5	8.8	9.1
1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.3
3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4
4.23	4.13	4.04	3.95	3.85	3.79	3.75	3.73	3.71
2.02	2.02	2.03	2.03	2.03	2.04	2.04	2.04	2.04
30.22	30.01	30.11	30.18	29.97	30.24	29.99	30.19	30.35

2029	2030	2031	2032	2033	2034	2035

2029	2030	2031	2032	2033	2034	2035	2008-2035
6.4	6.5	6.6	6.8	6.8	6.9	7.0	0.1%
0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.1%
2.4	2.4	2.4	2.4	2.4	2.4	2.4	0.0%
9.5	9.8	10.3	10.7	11.0	11.4	11.7	2.1%
1.3	1.3	1.4	1.4	1.5	1.5	1.5	3.0%
3.5	3.6	3.6	3.7	3.8	3.9	3.9	1.9%
3.62	3.70	3.66	3.70	3.64	3.64	3.77	-2.6%
2.04	2.05	2.05	2.06	2.06	2.06	2.07	-1.4%
30.14	30.45	30.26	30.03	30.38	30.25	30.47	-1.5%

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UE 215 – CERTIFICATE OF SERVICE

I hereby certify that, on this 4th day of June, 2010, I served the foregoing **OPENING TESIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket UE 215 upon each party listed in the UE 215 OPUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending 1 original and 5 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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