BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180

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

OPENING BRIEF
OF THE
CITIZENS' UTILITY BOARD OF OREGON

November 17, 2006

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180

In the Matter of	)	
	)	OPENING BRIEF OF
PORTLAND GENERAL ELECTRIC,	)	THE CITIZENS' UTILITY BOARD
	)	OF OREGON
Request for a General Rate Revision.	)	

I. Introduction

The Citizens' Utility Board is signatory to a number of recent stipulations that resolve many of the issues raised in PGE's general rate case filing. Though many of issues in this docket have been settled or have been withdrawn by the Company, a number of critical issues remain. We address those remaining issues here.

PGE's proposed power cost framework is unacceptable from both a practical and policy standpoint. The Company's proposed mechanisms do not recognize recent precedent established by the Commission, would layer one regulatory proceeding onto another, and would shift virtually all risk of power cost variations onto customers. In response to PGE's proposed caravan of mechanisms, and in reaction to the deluge of recent power cost filings, CUB proposes a power cost adjustment based on Commission precedent, sound regulatory policy, and a reasonable balance of risk and reward.

In this rate case, PGE proposes to enter its new gas plant, Port Westward, into rate base. This raises a number of issues. First, Port Westward is only one of a number of resources acknowledged in the Company's Action Plan which resulted from its last Integrated Resource Plan. The prudence of PGE's investment in Port Westward cannot be evaluated in a vacuum; the plant is part of a larger whole, and without the other pieces of that whole, the plant cannot be considered part of a prudently developed resource portfolio. Second, PGE filed this general rate case such that Port Westward would not be online when the ensuing rates go into effect. Like Port Westward's place in a larger Action Plan, Port Westward also has a place in the setting of overall rates. If Port Westward does not come online as scheduled, the overall balance of costs upon which rates were based will be out of kilter. Third, the Company has chosen to model power costs in January and February, before Port Westward is scheduled to come online, by prorating a 12-month MONET run that includes 10 months of an unmanaged power supply position the size of Port Westward. No prudent utility would actually leave such a position open, and the Company's modeling choice costs customers $1 million over those two months.

In addition to the Company's proposed regulatory framework and convoluted Port Westward approach, PGE has also requested a return on equity and capital structure that are inappropriate and burden customers with the Enron hangover. Finally, PGE wishes to include all, or part, of the 2005-06 Boardman outage in Boardman's forced outage rate. We find this to be a self-serving use of a methodology designed to forecast normal forced outage rates. Staff, ICNU, and CUB concur that the use of independently-produced

NERC data to establish a reasonable forced outage rate would be a preferable methodology.

II. Regulatory Framework For Variable Power Costs

In Direct Testimony supporting the rate case application, PGE requests, among other things, approval of both an RVM and a PCA.[1] PGE/100/Piro-Lesh/6. In this section, we will review the Commission precedent as we understand it, explain why an RVM is neither desirable nor necessary, and demonstrate why PGE's proposed PCA mechanism is wrong from a policy and precedent point of view. We offer instead a PCA which provides a fairer balance between customers and the utility, and is a better reflection of good policy and Commission precedent. We end with a short analysis of Staff's proposed PCA which, while more like CUB's proposal, does differ from the proposals of PGE and CUB.

A. Commission Precedent

The policy consideration underlying the design of a PCA is how the cost variations should be shared between shareholders and customers. The Commission has been faced with the same basic question in dealing with deferral applications. In UM 1071, the Commission called for a deadband in deferral dockets "reasoning that the band represent[s] risk assumed, or rewards gained, in the course of utility business." UM 1071 Order No. 04-108, p. 8-9. Under normal circumstances, the utility takes the risk of variations in costs from what was forecast. In circumstances that are outside the normal course of utility business, this risk can reasonably be shifted to customers. A

[1] PGE is now calling its RVM an Annual Update, and a PCA an Annual Variance. We continue to use RVM and PCA, because these are the terms that have been in place for these concepts.

deadband is used to represent risks within the normal course of utility business and to define what constitutes unusual or extraordinary.

The Commission further refined its policy with regard to PCAs when it considered a hydro-only PCA in UE 165. The Commission established four basic design criteria. The PCA should: 1) be limited to unusual events; 2) not allow adjustments if overall earnings are reasonable; 3) be revenue neutral; and 4) be appropriate for long-term operation. UE 165 Order No. 05-1261, p. 8-10. All four of these design elements go toward the policy of sharing cost variations between customers and shareholders. Limiting recovery of costs under a PCA to unusual events, and only when overall earnings are outside the reasonable range, is a reflection of the same policy stated in UM 1071. Before customers should share variations in power costs, the mechanism will represent the "risk assumed, or rewards gained, in the course of utility business." The long-term operation elements simply means that if a PCA is in place for an extended period of time it allows for a greater set of offsetting events to be reflected in rates, and may provide an opportunity to establish a lower deadband than in a deferral mechanism.

B. Principles

The following are principles we draw upon to analyze PGE's and Staff's proposed mechanisms, as well as to develop CUB's proposed power cost adjustment. These principles have been generally described by CUB in testimony.

1. Properly Allocate Risk: A utility is paid a rate of return to manage and absorb normal business risk and compensate investors for the risk of their investment. It is the utility's responsibility to manage a reasonable amount of cost variation which is a part of the risks and rewards of utility business. As power cost variations move

beyond the range of reasonable, it is appropriate for customers to step in and share a part of those risks and rewards. When power cost variations reach a substantial level, customers may be better able than the utility to absorb the cost. Even when power cost variations are substantial, however, costs and benefits should always be shared to some extent because of the incentive it provides the utility, as described below.

2. Promote Fairness: An ongoing mechanism should not favor either the shareholder or the customer. Revenue neutrality and the utility's return on equity are tools that can be used to ensure that neither the shareholder nor the customer absorbs undue risk or reward.
3. Reduce Rate Volatility: Rate volatility is undesirable; it makes planning and budgeting for energy expenses difficult for customers. In addition, sharp jumps in rates, as seen after the Western Power Crisis, can impact the state economy as a whole.
4. Provide Appropriate Incentives: Regulation should provide incentives for a utility to perform well, and manage power costs appropriately. The utility, and not the customer, is better able to react to changing circumstances, and actively manage power costs in a dynamic market.
5. Minimize Regulatory Burden: While maintaining a sound, equitable regulatory structure, the procedures and mechanisms used should be designed to use the least amount of resources for any given goal. The number of filings that are required and the amount of contention in each filing should be minimized. In the same vein, wherever possible, the regulatory expectations for the balance of risk and reward between customers and shareholders should be established in an ongoing manner and

before specific costs come into question. This removes the contention over this balance in every individual filing, and establishes this balance without the prejudice of specific costs.

C. Practices

In light of the principles we describe above, we describe the mechanisms and components thereof that meet the need of balancing the risks and rewards of power cost variations between general rate cases. PGE requests approval for both an RVM and a PCA in this rate case. In addition, PGE currently has an application before the Commission for a deferral of Boardman outage related costs (UM 1234). Of these three mechanisms, a power cost adjustment is best suited to manage power cost variations between rate cases in an equitable manner over time. However, the PCA should meet certain principles of fairness and reflect good regulatory policy.

i. A PCA Is A Better Tool For Power Cost Variations Than Deferrals Or The RVM

A power cost adjustment addresses power cost variations between general rate cases better than a deferral or the RVM. Unlike a deferral, a PCA is established ahead of time, and so the details of the mechanism are established prior to applying the mechanism to actual power cost variations. A power cost deferral will typically only be filed at the utility's discretion, because the utility has the power cost information and will only file when it is in the utility's interest.

The continuity of a PCA also serves to reduce the regulatory burden, as the details of the mechanism are pre-established, and so don't need to be litigated as they would for each individual deferral. Finally, a PCA eliminates the utility's risk of regulatory lag that exists when using deferrals to manage power cost variations. CUB/200/Jenks-Brown/20.

When a PCA is established, a utility is covered for events of unusual and/or extraordinary frequency, and so doesn't have to spend time deciding whether or not to file for a deferral when it should be focused on managing the circumstances at hand.

A PCA eliminates the need for PGE's annual RVM, because power cost variations outside of a reasonable range are captured by the mechanism, and so annually updating the Company's power cost forecast becomes overkill and time-consuming, if not outright redundant. Staff/800/Galbraith/14, CUB/200/Jenks-Brown/12-15, CUB/300/Jenks-Brown/28-29. In addition, the Company's RVM pretty much guarantees annual rate changes, whereas a properly designed PCA would only change rates if the utility's earnings were outside of a reasonable range. Given these distinctions between power cost adjustments, deferrals, and the Company's RVM, a PCA is better suited to address power cost variations equitably over time.

ii. PCA Components: Power Cost Deadband, Sharing Bands & Earnings Deadband

The components of a power cost adjustment that guide the mechanism's impact are its power cost deadband, its sharing bands, and its earnings deadband. Each of these components serves a different purpose.

a. Normal, Unusual, & Extraordinary Framework Applied to Deadband & Sharing Bands

The power cost deadband defines the range of power cost variation that is reasonable for a utility to absorb in the normal course of doing business. The deadband establishes the policy that it is the utility's responsibility to absorb a certain level of power cost variation, for better and for worse, and the deadband also defines what a reasonable range of variation is. This means that a power cost adjustment mechanism will only be triggered for events outside the normal course of doing business. As long as a utility is paid a return on equity, this is crucial, because a mechanism that shifts to customers the risk of normal power cost variations profoundly changes the established risk and reward balance in Oregon regulation.

The Commission and the parties have recently spent a great deal of time examining power cost variations, the events that cause variations, and the magnitude of those variations. Power cost variations were central to the discussions in UM 1147, an exploration of deferrals. In PGE's hydro deferral, UM 1071, and the Company's deferral/PCA dockets, UE 165/UM 1187, the issue of classifying hydro events by frequency was addressed. In its Order in UE 165, the Commission integrated these concepts by distinguishing between normal events (*i.e.*, not unusual), unusual events, and extraordinary events, based on frequency of occurrence.

> A hydro-related PCA should be designed so that recovery or refund occurs only if the hydro event is unusual. An unusual event is less extreme; *i.e.*, more likely to occur, than one that is considered extraordinary. In Docket No. UM 1071, we deemed a 1 in 4.5-year event not extraordinary enough for deferred accounting, but we consider it unusual enough for recovery or refund under a hydro-related PCA. The inclusion of a deadband around expected power costs is a reasonable way to identify whether an event is unusual.

UE 165 OPUC Order No. 05-1261, p. 9.

This Order provides a potential framework for approaching the design of a power cost adjustment. Power cost variations outside of a normal range, *i.e.*, those caused by unusual or extraordinary events, may be shared with customers.[2] At no point, however, should the entirety of power cost variations be placed on customers, as we mention earlier, because, in place of competition, regulation should always provide at least some incentive for a utility to manage power cost variations. Within a power cost adjustment,

---

[2] In CUB's Opening Testimony, we designed an all-power-cost PCA to capture only extraordinary, but not unusual, events. In Surrebuttal, we adjusted our proposed deadband and sharing bands to account for the financial impact of SB 408. In so doing, CUB's proposed deadband now captures events of unusual frequency as defined by the Commission in Order No. 05-1261. See section II.D.ii., below.

sharing bands prescribe the ranges of costs resulting from unusual and extraordinary events, and establish the appropriate sharing of those costs. Once power costs go outside the range associated with normal business variation, those costs or benefits can reasonably be shared between customers and shareholders. These moderate excursions from normal business variability should be only moderately shared. Beyond a range of unusual power cost variations, extraordinary power cost variations may be largely shifted to customers, though the utility should always have some skin in the game.

b. An Earnings Deadband Prevents Rate Changes When Earnings Are Reasonable

The earnings deadband serves the basic premise that money need not change hands when a utility's earnings are within a reasonable range. This reduces the potential for rate volatility, and adds a common-sense backstop to a power cost adjustment mechanism. A properly designed PCA defines normal business risk, shares the costs and benefits from unusual and extraordinary events, and changes rates only when the utility's earnings are outside of a reasonable range.

D. Principles and Procedures Applied To The Proposals

The principles with which we introduced this section and with which we analyze the power cost adjustment proposals before this Commission are:

1. Properly Allocate Normal, Unusual, and Extraordinary Risks
2. Promote Fairness
3. Reduce Rate Volatility
4. Provide Appropriate Incentives
5. Minimize Regulatory Burden

i. ***PGE Power Cost Adjustment Mechanism***

PGE's proposed regulatory framework is contrary to all of the principles we identified earlier. A summary of PGE's proposal follows:

PGE	Basis Points of ROE Equivalent		Sharing Customers - PGE
Deadband	None	None	N/A
Inner Sharing Band	None	None	N/A
Outer Sharing Band	0	0	90% - 10%
Earnings Deadband	None	None	N/A
Earnings Sharing	N/A	above +100	50% - 50%
Amortization Cap	Not Specified		
Annual RVM-Update	Yes		

PGE/400/Lesh-Niman/3

PGE's proposal does not properly allocate the costs from normal, unusual, or extraordinary events. Indeed, the Company's proposal allocates 90% of power cost variations to customers from the starting gate. PGE's proposal does not accept that there is any normal range of power cost variation in the electric utility business that the Company should have to absorb, so PGE does not include a deadband in its PCA proposal. PGE/400/Lesh-Niman/40. Instead, PGE inappropriately compares a PCA for power costs of an integrated electric utility to the purchased gas adjustment for the distribution gas utilities. *Ibid.*

PGE is not "aware of any regulatory policy reason" for applying a deadband. *Id.* at 43. PGE conveniently forgets that an electric utility is different from a gas distribution utility. CUB/300/Jenks-Brown/23. PGE conveniently forgets that it has supported a deadband for five years. *Id.* at 26. PGE conveniently ignores that the Commission has stated a policy reason for a deadband. UM 1071 Order No. 04-108,

p. 8-9, quoted in section II.A., above. And PGE forgets that its authorized return on equity is supposed to be pegged commensurate with the risk shareholders take. See discussion below in section IV.C. of *Federal Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The Company also does not acknowledge that there is any gradation in power cost variations or the risks thereof, and shares all power cost variations at the 90%-10% level regardless of whether normal, unusual, or extraordinary. PGE/400/Lesh-Niman/33.

The Company's proposal fails any measure of fairness. PGE's mechanism has neither a deadband nor sharing bands, so these bands cannot be used to account for the asymmetry of the magnitude of power cost variations. In UE 165, the parties discussed the power cost variations associated with good hydro conditions as opposed to poor hydro conditions. Specifically, the parties all agreed that the magnitude of power cost variations from poor hydro tends to be greater than that from good hydro. UE 165 CUB/100/Jenks-Brown/20 & CUB/200/Jenks-Brown/31-32, UE 165 Staff/100/Galbraith/12 & Staff/300/Galbraith/9, UE 165 PGE/100/Lesh/10 & PGE/200/Lobdell/16.

> The basic economic principles of supply and demand cause the skewed outcomes. Prices are higher when there is a shortage of hydro generation, and lower when there is "excess" hydro generation. The particular characteristics of electric markets accentuate this basi[c] relationship. Short-term demand for electricity is quite inelastic … With the Northwest's large amount of hydro resources … supply can vary significantly in the short-term. In low water years, all hydro resources in the region produce less energy. This causes a relative scarcity in supply to meet the relatively constant demands of customers of all electric suppliers in the region. That scarcity drives prices higher, with the upper limit of prices likely to be very high. In contrast, in high water years, there is a relative abundance of power to serve the same relatively constant load. This drives prices lower but, even theoretically, the price cannot fall below zero.

UE 165 PGE/100/Lesh/10.

> The symmetric [PCA] deadband is likely to create an expected value windfall for PGE. PGE witness Lobdell has testified that the costs of replacement power in poor hydro years outweigh the benefits of additional power in good hydro years. PGE Exhibit 200 Lobdell/2. A symmetrically designed [PCA] mechanism that tracks the asymmetric financial impacts of hydro variability can be expected to produce a balancing account balance that favors PGE.

UE 165 Staff/100/Galbraith/12.

> I indicated that a symmetrically designed adjustment mechanism that tracks the asymmetric financial impacts of hydro variability can be expected to produce a deferral balance that favors the utility.

UE 165 Staff/300/Galbraith/9.

The Commission, in concert with these discussions, made revenue neutrality a design criteria in its Order in UE 165. UE 165 OPUC Order No. 05-1261 at 10. Though the discussion in UE 165 centered around a hydro-only mechanism, many of the principles are the same. First, the Northwest region as a whole is heavily dependent upon hydro generation. Second, as Ms. Lesh points out, electricity prices can rise to infinity, but will only drop to zero. Also, the principles of supply and demand, as well as the market's reaction to a scarcity of electricity, discussed by Ms. Lesh, pertain to electricity in general and not just to hydro-generated electricity. Therefore, a power cost mechanism should have an asymmetric deadband and asymmetric sharing bands to yield revenue neutrality over time.

In addition, rather than proposing an earnings deadband, as the Commission describes in its UE 165 Order, PGE instead proposes to share, 50-50, any earnings in excess of 100 basis points over its authorized ROE updated from its last general rate case. PGE/400/Lesh-Niman/3. However, the Commission's design criteria from its UE 165 Order is "No Adjustments if Overall Earnings are Reasonable." UE 165 Order No. 05-1261, p.9. The purpose of this design criteria is to avoid surcharges to customers when the Company's earnings are reasonable and refunds to customers when the Company is under-earning. PGE's proposal, on the other hand, would require surcharges even if the Company were over-earning, and refunds even if the utility were under-earning.

PGE's proposal is a study in rate volatility. The Company's proposed PCA, for all practical purposes, ensures an annual rate change. In its proposal, the Company makes no attempt to reduce the volatility of annual rate changes, but assumes that the Commission has control over the amortization of any variances. *Id.* at 43. We do not think this is a realistic assumption, especially in the context of a long-term mechanism that should minimize the regulatory burden. Annual adjustments add volatility to rates and rate changes should not be necessary or desirable from a policy, and therefore a mechanical, perspective if the utility is earning within a reasonable range. CUB/300/Jenks-Brown/23-24.

Finally, the Company's proposal increases the already-cumbersome regulatory burden associated with variable power costs. Instead of streamlining the process for addressing power cost variations, PGE's proposal would layer a power cost adjustment mechanism on top of the Company's annual RVM, which the Company now calls an Annual Update. Under PGE's proposal, every year the parties would be involved in both a prospective RVM and a retrospective PCA. We could look forward to an annual battle of the adjustment mechanisms. Both Staff and CUB oppose PGE's multi-mechanism proposal, and find that an appropriate power cost adjustment negates the need for an annual RVM process. Staff/800/Galbraith/14, Staff Prehearing Brief at 7, CUB/200/Jenks-Brown/12-15, CUB/300/Jenks-Brown/28-29. In addition, under PGE's proposal, the parties and/or the Commission would have to determine an updated ROE annually between rate cases for the Company's skewed earnings test. PGE/400/Lesh-Niman/3.

On all fronts – proper risk allocation, equity, rate volatility, incentives, and regulatory burden – PGE's proposed power cost adjustment and RVM would be contrary to sound regulatory policy. To defend its proposal, PGE ignores or tries to explain away the past five years of regulatory proceedings, including positions supported by the Company itself. PGE believes deferrals do not count as precedent, because they are deferrals. PGE/1800/Lesh/43. Any docket with a stipulation doesn't count, because stipulations are not precedent. *Id.* at 46. The Commission's UE 165 decision doesn't count, because the Commission was wrong. *Ibid.* In addition, the way the Commission and stakeholders have looked at risk for the past five years is wrong too. CUB/300/Jenks-Brown/13-19.

As a postscript, the Company's Sursurrebuttal exploration of a "risk premium" deadband should be dismissed. PGE/2400/Lesh/21-23. PGE and the parties have been discussing these issues for half a decade or more, and the introduction of this strategy in the Company's Sursurrebuttal, after other parties have submitted their final rounds of testimony, is inappropriate. If the Commission wishes to pursue PGE's "risk premium" concept in this docket, the record should be reopened to allow the parties to respond.

ii. CUB Power Cost Adjustment Mechanism

The following is a summary of CUB's PCA proposal, adapted to account for the rules implementing SB 408. The adjustment to the size of the deadband and sharing bands we made in Surrebuttal does two things: it ensures that shareholders will not absorb any additional financial risk after SB 408 than they would have under our original proposal; and it increases the frequency that the PCA will trigger rate adjustments, so that it now captures what the Commission defined as unusual events.

CUB	Basis Points of ROE Equivalent		Sharing Customers - PGE
Deadband	above -75	below +150	0% - 0%
Inner Sharing Band	-120 to -75	+150 to +240	50% - 50%
Outer Sharing Band	below -120	above +240	90% - 10%
Earnings Deadband	above -100	below +100	0% - 0%
Earnings Sharing	None	None	N/A
Amortization Cap	6%		
Annual RVM-Update	No		

CUB/300/Jenks-Brown/27-28

CUB's proposed power cost adjustment mechanism, with a deadband and sharing bands adapted for SB 408, allocates the power cost variations of normal business activity to the utility, shares 50-50 between customers and shareholders power cost variations that are unusual, and allocates 90% of exceptional power cost variations to customers, while maintaining the utility's involvement with a 10% allocation of those cost variations to shareholders. CUB/300/Jenks-Brown/26-28. This progression from the everyday risk of ordinary power cost variations, to the infrequent risk of unusual variations, to the rare risk of extraordinary variations, provides a cohesive strategy for sharing power cost variations between customers and shareholders in a balanced manner.

CUB uses an asymmetric deadband and sharing bands in order to design the mechanism to be revenue neutral over time. As discussed above, the magnitude of higher-than-forecast power cost variations tends to be higher than that of lower-than-forecast variations, so to make the mechanism fair and balanced, the deadband and sharing bands should be asymmetric. The deadband and sharing bands in CUB's mechanism may not result in perfect revenue neutrality, but they can be adjusted over time. The other option, a symmetric deadband and sharing bands, cannot reasonably be expected to yield revenue neutrality.

CUB's proposal is to retire PGE's annual RVM and introduce a PCA for the Company. PGE's current annual RVM proceedings involve annual rate changes. Any mechanism offering the possibility of fewer rate changes would reduce the rate volatility experienced by customers. CUB's mechanism would ease the burden of rate volatility, presuming the RVM is retired, by only changing rates if power cost variations were outside of a normal business range and if the Company's earnings were also outside of a reasonable range. Under CUB's proposal, customers' rates would only change in unusual circumstances, as opposed to every single year. CUB/200/Jenks-Brown/17.

In regard to providing the utility with the proper incentives for active and aggressive power cost management, CUB's proposed PCA provides an appropriate progression of incentive levels for the utility to effectively manage power cost variations, from everyday variations, to unusual variations, to extraordinary ones. Running the utility is the Company's job, and it is a responsibility the Company is in a position to manage. Customers, on the other hand, are not in a position to manage daily power costs. For unusual power cost variations, CUB's mechanism lessens the Company's incentive, but keeps the Company actively in the field. When power cost variations become extraordinary, CUB's PCA asks customers to carry the preponderance of the burden, but ensures that the utility has just a bit of skin in the game. CUB/200/Jenks-Brown/11,19.

CUB's mechanism also meets the principle of minimizing the regulatory burden. In replacing PGE's annual RVM with a power cost adjustment mechanism, CUB's proposal removes the guarantee of annual rate changes with the ensuing contention, it removes the need to file power cost deferrals with the ensuing contention, it establishes an equitable mechanism that can remain in place over time, and, in settling the issue of power cost variations, it releases the utility and the parties from what has been an enormous time sink and allows them to address other interests and concerns.

iii. Staff Power Cost Adjustment Mechanism

The following is a summary of the Staff PCA proposal.

Staff	Basis Points of ROE Equivalent		Sharing Customers - PGE
Deadband	above -150	below +150	0% - 0%
Inner Sharing Band	None	None	N/A
Outer Sharing Band	below -150	above +150	90% - 10%
Earnings Deadband	above -100	below +100	0% - 0%
Earnings Sharing	None	None	N/A
Amortization Cap	Not Specified		
Annual RVM-Update	No		

Staff Prehearing Brief at 7

Though Staff's and CUB's proposed mechanisms differ, they share a number of fundamental principles. Staff and CUB both argue that PGE's RVM would be unnecessary if the Company were to have a power cost adjustment mechanism, and that the RVM has proven contentious and time-consuming while providing little, if any, benefit. CUB/200/Jenks-Brown/12-15, CUB/300/Jenks-Brown/28-29, Staff/800/Galbraith/13-14, Staff/1500/Galbraith/2. Staff and CUB also both adopt the Commission's proposed earnings deadband from the UE 165 Order. CUB/200/Jenks-Brown/22, CUB/300/Jenks-Brown/27, Staff/800/Galbraith/15-17.

Like CUB's proposal, Staff's power cost adjustment uses a deadband to limit the mechanism to unusual and extraordinary events. CUB and Staff both recognize the importance of maintaining some sharing, even for extraordinary power cost variations, in order to provide an incentive for the utility to manage those costs effectively. Staff and CUB also agree that an appropriate measure for normal power cost over-runs is 150 basis points of return on equity.

> Staff has recommended using a deadband to prevent normal variation in NVPC from triggering the PCA mechanism. Staff believes a deadband is the best way to protect shareholders from extreme increases in NVPC without shifting too much risk to customers. A large deadband serves two purposes. First, it keeps PGE focused on managing power cost risk …

> Second, a large deadband prevents the PCA mechanism from supplanting normalized test year ratemaking.

UE 180 Staff/1500/Galbraith/11.

In addition, both CUB and Staff acknowledge the Commission's goal that an ongoing mechanism be revenue neutral over time. UE 165 OPUC Order No. 05-1261, p. 8-10. CUB actively pursues revenue neutrality through the use of an asymmetric deadband and sharing bands. Staff, while acknowledging the Commission's goal, simply notes that it is unclear if Staff's proposed mechanism would be revenue neutral. Staff/800/Galbraith/18. Given that Staff, CUB, ICNU, and PGE have all testified that the magnitude of power cost over-runs tends to be greater than the magnitude of lower-than-forecast power cost variations, it seems highly unlikely that a symmetric deadband and sharing bands would meet the Commission's revenue-neutral criteria. See section II.D.i., above. As the magnitudes of higher-than-forecast and lower-than-forecast power cost variations are asymmetric, a symmetric deadband and sharing bands would result in a greater dollar amount being collected from customers for high power costs, and a lesser dollar amount being returned to customers for low power costs. This imbalance would not be compatible with the principle of fairness we describe earlier.

In addition to the use of a symmetric deadband and sharing bands, Staff's proposal also differs from CUB's in the progression and sharing percentages of these bands. Staff's proposal does not contain any gradation in sharing bands. The categorization of risks, events, and cost variations as normal, unusual, and extraordinary has proven useful in discussions addressing power cost variations. It stands to reason that, as events and their costs follow a progression from mundane to extraordinary, a mechanism to address such events and costs could also follow that progression. Though an unusual-event sharing band and sharing percentages are absent in Staff's proposal, Staff does acknowledge the importance of sharing at all levels to align the Company's interests with those of the customer. Staff/800/Galbraith/16.

Staff's proposed power cost adjustment mechanism, though similar to CUB's in many ways, is extremely unlikely to be revenue neutral over time and does not appropriately allocate normal, unusual, and extraordinary power cost variations. For reasons of fairness and appropriate risk allocation, CUB's proposal better meets Oregon's regulatory framework.

III. Port Westward

There are three issues revolving around the Port Westward plant that warrant attention. First, we address the prudence of Port Westward in the absence of the acquisition of other resources included in PGE's 2002 IRP Action Plan. Second, we discuss the treatment of Port Westward in rates if the online date of the plant is delayed beyond that assumed by PGE in testimony. Third, we address how MONET models the online date of Port Westward in the test year power costs.

A. The Prudence Of Port Westward In Relation To PGE's IRP

In testimony, CUB examined the prudence of Port Westward in the context of the other resource acquisitions outlined in the Company's 2002 IRP Action Plan. CUB/100/Jenks-Brown/32, CUB/300/Jenks-Brown/29-31. It was unclear to us how PGE could establish the prudence of a single plant when the acknowledged Action Plan contains a mix of resources.

i. A Gas Plant Was Acknowledged As Part Of A Portfolio Of Resources

When the Commission acknowledged (with conditions) PGE's 2002 IRP in LC 33, the Commission said that acknowledgement…

> … means that the specific resource actions, when combined with other action items, should result in "the mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs."

LC 33 OPUC Order No. 04-375, p. 12, quoting OPUC Order No. 89-507, p. 2.

What is an Action Plan and what does acknowledgement mean if the utility develops only a subset of generation options, and does not pursue the best combination of options outlined in the Action Plan? Specifically, PGE provided no information on the progress of the significant renewable energy component of its Action Plan. As we said in the IRP process and in this case, a gas plant optimized by renewable energy acquisitions may be prudent, but a gas plant in the absence of renewable energy acquisitions may not be prudent.

Staff agreed that CUB's concern was "valid," stating that "PGE's action in relation to the entire 2002 IRP action plan is an important consideration in evaluating the prudence of Port Westward." Staff/1500/Galbraith/21. Staff goes on to say that individual resource decisions can still be prudent even if the Action Plan implementation is imperfect. We will address this policy issue in the next section, but for the purposes of the evidence underlying the prudence review, our reading of PGE's case left us with the feeling that there was an insufficient evidentiary record to establish a prudence finding.

Even PGE says the issue is valid, and, in response to CUB's concern, PGE offered the testimony of Jim Lobdell to provide a progress report on PGE's actions to acquire between 126 MW and 450 MW of wind at the Biglow Canyon site.

PGE/2500/Lobdell. For the time being, PGE's response is sufficient to create a prima facie case of prudence, given the activity on the renewable energy acquisitions. However, this give and take produced a disturbing statement from Staff which leaves us wondering how the Commission views IRPs, Action Plans, prudence reviews, and reasonable rates.

ii. The Policy Of Un-combining A Resource That Is Part Of A Prudent Portfolio

In making its case that Port Westward is prudent, not only does PGE provide information on the record that indicates that the Company was actively pursuing the renewable energy resources in its Action Plan, the Company also sought policy help from Staff witnesses on determining the prudence of one resource in isolation from its Action Plan. Staff responded to a data request from PGE on CUB's view of the prudence debate. In part the data response reads:

> CUB, in its rebuttal testimony, indicated that it could not determine, at this time, the prudence of PGE's decision to build Port Westward and that the prudence of the investment will become more clear over time. CUB suggests that if PGE does not acquire the renewable resources included in its 2002 IRP Final Action Plan, then PGE's decision to build Port Westward may become imprudent. See CUB/300, Jenks-Brown/31. Staff does not agree with CUB's approach to determining the prudence of Port Westward. If PGE does not acquire the renewable resources included in its 2002 IRP Final Action Plan, then the decision to not acquire the renewable resources could be the subject of a prudence challenge in a future rate proceeding. A potential adjustment in that future rate proceeding would be to impute the foregone renewable resources in PGE's rates. Staff believes that CUB's prudence challenge is misdirected. The challenge has more to do with PGE's decision-making with respect to renewable resources than it does with PGE's decision to build Port Westward.

UE 180 PGE/2501/Lobdell/1, Staff response to PGE data request 085.

Staff's response is disturbing for a number of reasons. First, it is based on an unrealistic premise that any party has ever been able to or will ever convince a

Commission several years after the fact that rates should be imputed for a resource decision that was NOT made. We are not aware of a Commission decision that has imputed the costs or benefits of a utility decision to not acquire a resource that was contained in an IRP Action Plan. It borders on silly to say that this is an appropriate policy for handling the acquisition of a few resources from the optimal mix contained in the acknowledged Action Plan.

Second, not only is there not a history of such an imputation, but the logistics of making the rate imputation of a specific resource not acquired in the future is daunting. It seems to us far easier and more accurate to revisit the rate treatment of the one facility built out of context by examining where the costs and benefits of the full Action Plan would have been had the utility fulfilled the promise of the Action Plan. The benefits of renewable energy may be realized several years down the road, and we have no confidence that a future Commission will remember Staff's data request answer and give a fair hearing to an argument that asks for the imputation of an action not taken. On the other hand, tracking the rate implications of an action taken out of context and comparing it with the assumed context seems eminently reasonable.

Third, we think that Staff's position makes Commission acknowledgement of an IRP and the Action Plan meaningless. Above, we quoted language from the Commission's acknowledgement of PGE's 2002 IRP. The Commission is basing its decision on the mix of options that creates the best combination of costs and variance of costs. There is no mix of resources and no best combination if the utility is allowed to build a resource out of context, and the only recourse is an unrealistic request that the Commission "revisit" the future value of an action not taken. Staff states in its testimony validating CUB's concern, "[i]ndividual resource decisions can still be prudent even though the utility's implementation of its entire action plan has been less than perfect." Staff/1500/Galbraith/21. However, individual resources also may NOT be prudent if the implementation of the Action Plan is "less than perfect". In fact, individual resource decisions made in contravention of the acknowledged Action Plan may very well turn an Action Plan from an optimal mix of resources to a plan that does not warrant acknowledgement.

Staff's position assumes only that individual resource decisions can still be prudent even if the utility fails to acquire the other optimal resource in the Action Plan. CUB is attempting to give some meaning to the acknowledgement of the best combination of resources. We want to do this to give integrity and meaning to the IRP process, but also because we have seen a consistent scenario play out where renewable energy resources are firmly identified in Action Plans, but cannot quite seem to make it to firmly placed in the ground. Fossil-fuel resources do not seem to have the same problem. Staff's solution is not good enough for us. It is unrealistic on a practical basis, and is flawed from a policy basis. Such a policy would convince us that acknowledgement of an IRP and an Action Plan has little meaning.

B. If Port Westward Is Delayed

The Commission will issue an order in this general rate case before Port Westward comes on line and is used and useful. We first raised this issue in the context of PGE's motion to consolidate Port Westward issues (UE 184) with the general rate case (UE 180). In our response, CUB opposed the consolidation, arguing that ORS 757.355(1) does not allow an investment in rates until it is shown that the investment is functioning and actually serves customers. UE 184 CUB Response to PGE Motion to Consolidate, May 8, 2006. Furthermore, if Port Westward is further delayed from its assumed online date, the match of costs and rates will be extended beyond what would be intended in the rate case order. Judge Smith granted PGE's motion to consolidate, but stated, "Staff and CUB raise valid concerns regarding the possible lag between approval of the Port Westward tariff and the date on which the plant actually goes into service. No conditions will be adopted at this time, but will be considered as they are raised during the proceeding." Ruling, May 12, 2006.

CUB did indeed raise this issue in our testimony. We said:

> UE 180 will end before Port Westward is used and useful, and the rates resulting from UE 180 will go into effect before Port Westward is used and useful. PGE is using this docket to seek pre-approval of Port Westward so the Company can avoid any regulatory lag associated with including the resource in ratebase. While the timing of this rate case offers PGE protection, it creates a problem for customers. If Port Westward is delayed, a disconnect will result between the effective rates for calendar year 2007 and the used and usefulness of Port Westward. The Company's overall revenue requirement is established based on the sum of all the Company's costs and revenues. A delay in Port Westward would put that relationship between those cost and revenues out of kilter . . .

UE 180 CUB/200/Jenks-Brown/27.

Even if the online date of Port Westward is as PGE assumes, there is the technical but very real used and useful problem. ORS 757.355(1) states:

> … a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.

Until such time as an investment is used and useful, ratepayers cannot be charged the costs associated with that investment. CUB raised a number of issues underlying the policy established in statute. As stated above, the timing of the actual online date for Port

Westward is divorced from the underlying costs used to establish rates. The way to recover the cost of a new useful investment is through a general rate case process, where all manner of costs can be examined, including some which may offset the capital costs of the new investment.

If the new investment, in this case, Port Westward, does not come on line when assumed, the disconnect between the underlying basis of rates and the cost of the new investment becomes even greater. Including the cost recovery of a plant not yet in service (besides violating the law) protects the utility, while exposing the customer to costs that are not beneficial and which could otherwise have been partially offset by declining costs. Indeed, the two (or more) month gap between the effective rates anticipated in January 2007 and the online date of Port Westward is entirely a product of the timing of PGE's rate case filing.

The Commission should avoid bad precedent and lack of discipline in setting rates. Port Westward represents a $45 million addition to revenue requirement and a $279 million addition to ratebase, almost a 16% increase. UE 180 CUB/200/Jenks-Brown/28. This is a significant investment from a customer point of view, and the Commission should handle the timing disconnect and the potential delay of the online date with some care.

CUB offered three conditions to the recovery of Port Westward costs:

1. As the Commission expects Port Westward to be used and useful early in this test period, the tariff associated with Port Westward should only be valid within 30 days of March 1, 2007.

2. If Port Westward is not used and useful within 30 days, the Company must reopen UE 180. Staff and intervenors should be given a limited period of time to review the Company's actual costs to determine whether there is new information that requires a reexamination of PGE costs before Port Westward is included in rates.
3. After six months, if Port Westward is not used and useful, the Company must file a new rate case in order to add the plant to ratebase.

These conditions alleviate the problem of establishing a revenue requirement before the costs become legally recoverable and before the costs themselves are even relevant. *Id.* at 30-31.

PGE acknowledges CUB's concern, but responds with revisions to CUB's conditions. PGE/1900/Tinker *et al.*/55-56. PGE would make the Port Westward tariff valid for three months before reopening UE 180, and would have the Commission not require a new rate case unless the online date were postponed beyond 2007. We appreciate PGE's willingness to work with CUB's conditions, but we also recognize that PGE's response, in effect, confirms our concerns. PGE could have timed the general rate case to more closely coincide with the online date of Port Westward and now PGE is proposing three months leeway. CUB stands by our initial set of conditions.

C. Port Westward In Power Costs

CUB identified a problem with the way PGE models Port Westward for the purpose of determining power costs. The problem is a product of the mismatched timing of the rate case and the online date of Port Westward, and is one of both inaccurate forecasting and unfairness, resulting in rates that are higher than they should be.

Because Port Westward comes on line two months into the 2007 test year, PGE has to model power costs for the year assuming that it is filling an open position for January and February with market purchases, but then running Port Westward for the remainder of the year. The method that PGE uses to forecast the January-February position (and additional months if Port Westward is delayed) inaccurately and unfairly raises rates during that period. CUB/100/Jenks-Brown/7-10.

The way PGE fills the 2-month period prior to Port Westward's scheduled online date and the 10-month period which includes Port Westward is to run two 12-month MONET runs. The first MONET run does not contain Port Westward at all, and though that MONET input contains an actively managed position for January and February, MONET fills the open position for March through December based on market price forecasts. That 12-month cost is then prorated to develop rates for January and February when Port Westward is not expected to be online. The second MONET run assumes Port Westward operates from March through December, with a managed gas supply, and these results are then prorated to develop rates from March through December.

The major problem with this methodology is that it over-estimates costs for the January through February period by including in the calculation prorated costs of an unmanaged open position from March through December. *Id.* at 7-8. In addition, this all assumes that Port Westward comes on line when scheduled in March. If the online date is delayed, say until July, then the Model continues the inaccurate and overestimated costs until Port Westward is up and running. Customers are charged the bloated costs of an unfilled <u>and unmanaged</u> position until Port Westward comes on line. So while we are paying the costs of an unmanaged open position, PGE is protected.

The effect of using the MONET run with this unmanaged open position can be seen by examining PGE's November 9th Update MONET runs. Attachment 1 of that filing contains a General Rate Case MONET run that includes Port Westward forecasted to begin operation on March 1, 2007 and a MONET run that excludes Port Westward for the entire year. The model run that includes Port Westward shows that total net variable power costs will be $6 million lower (an average of $500,000/month) than the model run that excludes Port Westward. PGE 2007 RVM and GRC MONET 11/09/06 Updates Attachment 1.[3]

While both model runs forecast the exact same net variable power cost for January and February, PGE's proposal to use the MONET run that excludes Port Westward to set rates in January and February will increase rates by approximately $1 million during that period. Costs will not be higher in January and February (they are the same), but rates will be higher due to the cost of including a large unmanaged open position from March through December in the MONET run that determines the rates for January and February. However, PGE does not really expect to have this large unmanaged open position. They are forecasting Port Westward to fill this position. But by excluding Port Westward from the forecast, PGE can charge higher rates before Port Westward comes on line.

PGE says that "it is fair that any associated dispatch benefits [of Port Westward] be withheld until the 'in-service' date." PGE/2600/Tinker *et al.*/32. However, the way that PGE has withheld the dispatch benefits of Port Westward is to charge customers more than they otherwise would be charged by imputing a pro rata share of the 10-month

[3] Though these MONET runs were mailed as confidential, PGE acknowledges that the total power cost numbers are not confidential and gave permission for this information to be used non-confidentially.

unmanaged position. Instead, PGE could simply use the sum of the managed January through February position plus the post-February period that contains Port Westward and its managed gas supply. This is what PacifiCorp agreed to in UE 170. CUB/100/Jenks-Brown/10. Just as importantly, this is what PGE is forecasting in 2007 – two months of managed purchases, followed by ten months of Port Westward.

It is unrealistic for the Company to have such a large, unmanaged capacity left to the vagaries of the market. PGE's methodology includes the prorated costs of this unrealistic strategy. By doing so, PGE collects more from customers than it should, and protects itself from actions that are of the Company's own making.

IV. Cost Of Capital

In Opening Testimony, PGE proposed a capital structure of 55.96% common equity, 0.29% preferred equity and 43.75% long term debt, with a 10.75% return on equity. PGE/1100/Hager-Valach/3-4. In surrebuttal, Staff recommended a 9.40% return on equity. Staff/1400/Morgan/2. Michael Gorman, witness on behalf of ICNU and CUB, recommends an ROE of 9.9% and a capital structure of 50.0% common equity, 0.29% preferred stock, and 49.71% debt.

A. Return On Equity

By examining DCF, Risk Premium, and CAPM analyses, Gorman recommends a 9.9% ROE. Based on these three analyses, he develops an ROE range from 9.5% to 10.4%. ICNU-CUB/300/Gorman/28. The 9.9% recommendation is the mid-point of the range developed from his analysis.

Gorman examines PGE's claims that, currently, the Company's market-required ROE falls within the range of 9.25% to 11.3%, and determines that PGE includes in its

DCF analysis returns that are unreasonable. While the majority of returns used in the PGE analysis fell within the range of 8.1% to 9.6%, only one estimate exceeded that range, an 11.2% return based on GDP growth. *Id.* at 31. Gorman recommends throwing out the higher return as it is "irrational" and "not sustainable or achievable." *Id.* at 32. By removing this extreme return, PGE's own analysis supports a ROE in the range of 9.7% to 10.4%. *Id.* at 2. This range is entirely consistent with Gorman's own analysis. Even PGE considers Gorman's recommended ROE within the range of reasonableness. PGE's Amended Prehearing Brief, p.11.

B. Capital Structure

Gorman's proposed capital structure is reasonable, and will maintain PGE's current credit rating. Gorman objects to PGE's proposed structure because it has "excessive amounts of common equity, which unnecessarily and unreasonably increases the revenue requirement." ICNU-CUB/300/Gorman/8. Instead, Gorman proposes a capital structure of 50.0% common equity, 0.29% preferred stock and 49.71% debt. In calculating his recommended capital structure, Mr. Gorman lists the reasons why his proposal is more reasonable than PGE's:

1. It will result in a lower revenue requirement and lower cost to customers in this proceeding.
2. This capital structure, in combination with PGE's off-balance sheet debt equivalence as estimated by S&P, meets S&P's credit rating financial benchmarks adequate to maintain PGE's current credit rating.
3. This capital structure is more comparable to industry average capital structures, and specifically the capital structure mix of the proxy group I use to estimate PGE's cost of common equity in this proceeding.

Id. at 9.

Gorman goes on to show that his recommended capital structure will support PGE's current rating, and that his proposal is more consistent with capital structures recently authorized in Oregon and the Northwest. *Id.* 9-12. Finally, Gorman explains that PGE's above-industry-average component of common equity is a vestige of Enron ownership, and PGE management efforts to isolate PGE from its bankrupt parent. *Id.* 13-14. It is a long-standing requirement that customers are to be protected from any increase in costs from Enron's ownership. *Ibid.*

C. ICNU-CUB ROE Proposal Does Not Implicate *Hope* or ORS 756.040

The general standard against which regulated rates are tested is the takings language discussed in *Federal Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). There is no specific "cost of capital standard" in *Hope*. In fact, the Court said that "[i]t is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry … is at an end." *Id.* at 602. The Court went on to say that the return should be commensurate with returns on investments having corresponding risks, and "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Id.* at 603. ORS 756.040, more or less, says the same thing.

There has been no genuine challenge to ICNU-CUB's testimony on ROE or capital structure that might be construed to implicate the *Hope* standard. Gorman has repeatedly pointed out that his proposal is more reasonable given the circumstances of the market and more consistent with recent regulatory orders in the region. ICNU-CUB's proposals on ROE and capital structure keep rates reasonable and well within any Constitutional standard, and allow PGE to earn a fair and reasonable return.

V. Forced Outage Rate

Staff, CUB, and ICNU all agree that the use of a four-year rolling average to determine the forced outage rates reflecting normal unit availability suffers from the inclusion of the extreme Boardman outage in 2005 that is the subject of a separate deferral application (UM 1234). These three parties testify that including the Boardman outage is not reasonable, and would not result in a representative view of a normal forced outage rate. Staff/100/Galbraith/6, CUB/100/Jenks-Brown/7, ICNU/103/Falkenberg/12. PGE, on the other hand, sees no problem including the extreme Boardman outage in the representation of a normally operating resource.

The parties who realize this is a problem offered numerous fixes from using a rolling average that excluded 2005 to using industry-wide data from NERC to establish forced outage rates. Staff comprehensively discusses the options. Staff/100/Galbraith/7-17. In the end, Staff, ICNU, and CUB landed on about the same place: it is appropriate to normalize a forced outage rate forecast using peer group performance statistics. Staff/100/Galbraith/17, ICNU/103/Falkenberg/14, CUB/300/Jenks-Brown/45.

CUB sees the advantages of having a more objective point of comparison that is derived from independently-produced statistics. The proposal is not specifically designed to remove the Boardman extreme outage situation, but part of its attractiveness is that it does remove the extreme events and creates a more representative forecast. PGE argues that this technique has not been demonstrated to be more accurate. PGE/1900/Tinker *et al.*/39-44. However, PGE's insistence on including the extreme outage calls into question PGE's authority to tell us what the most accurate methodology is. CUB/300/Jenks-Brown/46. Staff and ICNU have offered a competent case for use of peer group performance to determine the forced outage rate.

VI. Conclusion

We recommend the Commission:

Power Cost Adjustment and RVM

- Reject PGE's proposed Annual Variance mechanism;
- Adopt CUB's proposed Power Cost Adjustment mechanism containing a deadband and sharing bands, an earnings deadband, an amortization cap, and a prudence review; and
- Reject PGE's proposal to continue a new version of the RVM, now called the Annual Update.

Port Westward

- Make clear that, if PGE fails to achieve the fuel diversity that was envisioned in the Company's IRP, the prudence of Port Westward should be revisited;
- Condition approval of the tariff associated with Port Westward such that it will only be valid within 30 days of March 1, 2007;
- Condition approval of the tariff associated with Port Westward such that, if Port Westward is not used and useful within 30 days, the Company must reopen UE 180;
- Condition approval of the tariff associated with Port Westward such that, if Port Westward is not used and useful within 6 months, the Company must file a new rate case in order to add the plant to ratebase; and
- Remove $1 million from the Company's net variable power costs to compensate for the inclusion of ten months of an unmanaged, open position in the modeling of rates for January and February.

Cost of Capital and Capital Structure

- Authorize a return on equity for PGE of 9.9%, and a capital structure of 50% common equity, 0.29% preferred stock, and 49.71% debt.

Forced Outage Rates

- Adopt a method using NERC data to establish a forced outage rate for Boardman and Colstrip.

Respectfully Submitted,
November 17, 2006

Jason Eisdorfer #92292
Attorney for the Citizens' Utility Board of Oregon

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of November, 2006, I served the foregoing Opening Brief of the Citizens' Utility Board of Oregon in docket UE 180 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

Jason Eisdorfer #92292
Attorney for Citizens' Utility Board of Oregon

W=Waive Paper service, Q=Confidential

JIM DEASON ATTORNEY AT LAW	1 SW COLUMBIA ST, SUITE 1600 PORTLAND OR 97258-2014 jimdeason@comcast.net
ROBERT VALDEZ	PO BOX 2148 SALEM OR 97308-2148 bob.valdez@state.or.us
AF LEGAL & CONSULTING SERVICES	
ANN L FISHER ATTORNEY AT LAW	2005 SW 71ST AVE PORTLAND OR 97225-3705 energlaw@aol.com
BOEHM KURTZ & LOWRY	
KURT J BOEHM **(Q)** ATTORNEY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
MICHAEL L KURTZ **(Q)**	36 E 7TH ST STE 1510 CINCINNATI OH 45202-4454 mkurtz@bkllawfirm.com
BONNEVILLE POWER ADMINISTRATION	
GEOFFREY M KRONICK LC7 **(Q)**	PO BOX 3621 PORTLAND OR 97208-3621 gmkronick@bpa.gov

CRAIG SMITH	PO BOX 3621--L7 PORTLAND OR 97208-3621 cmsmith@bpa.gov

BRUBAKER & ASSOCIATES, INC.

JAMES T SELECKY **(Q)**	1215 FERN RIDGE PKWY, SUITE 208 ST. LOUIS MO 63141 jtselecky@consultbai.com

CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP

TAMARA FAUCETTE	1001 SW 5TH AVE STE 2000 PORTLAND OR 97204 tfaucette@chbh.com
CHAD M STOKES	1001 SW 5TH - STE 2000 PORTLAND OR 97204 cstokes@chbh.com

COMMUNITY ACTION DIRECTORS OF OREGON

JIM ABRAHAMSON **(Q)** COORDINATOR	PO BOX 7964 SALEM OR 97303-0208 jim@cado-oregon.org

CONSTELLATION NEWENERGY INC

WILLIAM H CHEN REGULATORY CONTACT	2175 N CALIFORNIA BLVD STE 300 WALNUT CREEK CA 94596 bill.chen@constellation.com

DANIEL W MEEK ATTORNEY AT LAW

DANIEL W MEEK ATTORNEY AT LAW	10949 SW 4TH AVE PORTLAND OR 97219 dan@meek.net

DAVISON VAN CLEVE PC

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

DEPARTMENT OF JUSTICE

STEPHANIE S ANDRUS **(Q)** ASSISTANT ATTORNEY GENERAL	REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us

EPCOR MERCHANT & CAPITAL (US) INC

LORNE WHITTLES MGR, PNW MARKETING	1161 W RIVER ST STE 250 BOISE ID 83702 lwhittles@epcor.ca

GRESHAM CITY OF

DAVID R RIS SR. ASST. CITY ATTORNEY	CITY OF GRESHAM 1333 NW EASTMAN PARKWAY GRESHAM OR 97030 david.ris@ci.gresham.or.us
JOHN HARRIS (Q) TRANSPORTATION OPERATIONS SUPERINTENDENT	1333 NW EASTMAN PKWY GRESHAM OR 97030 john.harris@ci.gresham.or.us

KAFOURY & MCDOUGAL

LINDA K WILLIAMS ATTORNEY AT LAW	10266 SW LANCASTER RD PORTLAND OR 97219-6305 linda@lindawilliams.net

LEAGUE OF OREGON CITIES

ANDREA FOGUE SENIOR STAFF ASSOCIATE	PO BOX 928 1201 COURT ST NE STE 200 SALEM OR 97308 afogue@orcities.org

MCDOWELL & ASSOCIATES PC

KATHERINE A MCDOWELL ATTORNEY	520 SW SIXTH AVENUE, SUITE 830 PORTLAND OR 97204 katherine@mcd-law.com

W **NORTHWEST ECONOMIC RESEARCH INC**

LON L PETERS	607 SE MANCHESTER PLACE PORTLAND OR 97202 lpeters@pacifier.com

NORTHWEST NATURAL

ELISA M LARSON **(Q)** ASSOCIATE COUNSEL	220 NW 2ND AVE PORTLAND OR 97209 elisa.larson@nwnatural.com
ALEX MILLER **(Q)** DIRECTOR, REGULATORY AFFAIRS	220 NW SECOND AVE PORTLAND OR 97209-3991 alex.miller@nwnatural.com

OREGON ENERGY COORDINATORS ASSOCIATION

KARL HANS TANNER **(Q)** PRESIDENT	2448 W HARVARD BLVD ROSEBURG OR 97470 karl.tanner@ucancap.org

PACIFICORP

LAURA BEANE MANAGER, REGULATION	825 MULTNOMAH STE 800 PORTLAND OR 97232-2153 laura.beane@pacificorp.com

W PORTAND CITY OF - OFFICE OF CITY ATTORNEY

BENJAMIN WALTERS DEPUTY CITY ATTORNEY	1221 SW 4TH AVE - RM 430 PORTLAND OR 97204 bwalters@ci.portland.or.us

W PORTLAND CITY OF - OFFICE OF TRANSPORTATION

RICHARD GRAY STRATEGIC PROJECTS MGR/SMIF ADMINISTRATOR	1120 SW 5TH AVE RM 800 PORTLAND OR 97204 richard.gray@pdxtrans.org

W PORTLAND CITY OF ENERGY OFFICE

DAVID TOOZE SENIOR ENERGY SPECIALIST	721 NW 9TH AVE -- SUITE 350 PORTLAND OR 97209-3447 dtooze@ci.portland.or.us

PORTLAND GENERAL ELECTRIC

RATES & REGULATORY AFFAIRS	RATES & REGULATORY AFFAIRS 121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
DOUGLAS C TINGEY **(Q)**	121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com

PRESTON GATES ELLIS LLP

HARVARD P SPIGAL	222 SW COLUMBIA ST STE 1400 PORTLAND OR 97201-6632 hspigal@prestongates.com

SEMPRA GLOBAL

THEODORE E ROBERTS	101 ASH ST HQ 13D SAN DIEGO CA 92101-3017 troberts@sempra.com
LINDA WRAZEN	101 ASH ST, HQ8C SAN DIEGO CA 92101-3017 lwrazen@sempraglobal.com

SMIGEL ANDERSON & SACKS

SCOTT H DEBROFF	RIVER CHASE OFFICE CENTER 4431 NORTH FRONT ST HARRISBURG PA 17110 sdebroff@sasllp.com