ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 22, 2006

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: August 14, 2006

TO: Public Utility Commission

FROM: Steve W Chriss

THROUGH: Lee Sparling, Ed Busch, Judy Johnson

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF: Request to open an investigation regarding performance-based ratemaking mechanisms to address potential build-vs-buy bias.

STAFF RECOMMENDATION:

Staff recommends that the Commission open an investigation regarding performance-based ratemaking mechanisms to address potential build-vs-buy bias in electric utility resource procurement. Going forward with this investigation will bring docket UM 1066 to final resolution.

DISCUSSION:

As part of the Commission's 2005-2006 objective of exploring the use of performance-based ratemaking (PBR) for the elimination of potential build-vs-buy bias in resource procurement, staff conducted research on potential barriers to the purchase of power purchase agreements (PPA) and appropriate mechanisms to address this bias. While there is not a standard definition for PBR, it is ultimately the promotion of optimal decision making with a utility's earnings depending on performance. Staff's findings can be found in Attachment A.

Staff identified four potential barriers to the purchase of PPAs:

1. The treatment of PPAs in credit scores, such as those calculated by Standard & Poors, Fitch, and Moody's;

2. The counterparty risk involved in entering into a PPA contract;

3. Utility-owned power plants earn a return as part of the utility's rate base, whereas PPAs do not; and

4. The concept of empire building, in which a utility may desire to accumulate assets for reasons other than providing power to customers on a least-cost basis.

As these barriers may inject bias into the resource procurement process, staff believes that it is appropriate to find a mechanism under which the potential bias is eliminated.

Staff identified a number of mechanisms which could potentially address the build-vs-buy bias. The mechanisms range from relatively simple procedural changes to wholesale changes in the regulatory regime. Staff organized the options as follows:

1. Reduction of regulatory risk only:
   Option No. 1: Expedited PPA Prudence Review and Allow Dollar-for-Dollar Cost Recovery

2. Monetary incentives:
   Option No. 2: Equity Offsets
   Option No. 3: Power Cost Adjustment Mechanism (PCAM)
   Option No. 4: Inclusion of PPA Contracts in the Rate Base
   Option No. 5: Generation Incentives

3. Elimination of rate base:
   Option No. 6: Price Cap Regulation

On a preliminary basis, staff recommends the use of Option 1, which is an expedited prudence review and dollar-for-dollar cost recovery for PPA contracts. This method provides incentives to the utilities because of the alleviation of debt equivalency issues and protects customers because the cost of the contract in rates is simply the cost of the contract. This process may also provide an incentive for the utilities to enter into least-cost contracts, as the Commission will have an immediate opportunity to investigate and approve the contracts.

PROPOSED COMMISSION MOTION:

The Commission investigate performance-based ratemaking mechanisms to address potential build-vs-buy bias in electric utility resource procurement.

Attachment A

PUBLIC UTILITY COMMISSION OF OREGON
INTEROFFICE CORRESPONDENCE

DATE: June 9, 2006

TO: Lee Sparling

FROM: Steve W Chriss

SUBJECT: **Performance-Based Ratemaking for the Elimination of the Build-vs-Buy Bias**

Summary

The memo is to report the findings of staff in regards to the Commission's 2005-2006 objective of exploring the use of performance-based ratemaking (PBR) for the elimination of the build-vs-buy bias in resource procurement. While there is not a standard definition for PBR, it is ultimately the promotion of optimal decision making with a utility's earnings depending on performance.

Staff discusses six different options for eliminating a potential build-vs-buy bias in resource procurement. These six options range from the simple (Option 1) to complex (Option 6.) On a preliminary basis, staff recommends the use of Option 1, which is an expedited prudence review and dollar-for-dollar cost recovery for PPA contracts. This method provides incentives to the utilities because of the alleviation of debt equivalency issues and protects customers because the cost of the contract in rates is simply the cost of the contract.

Discussion

The first potential barrier to the purchase of a PPA, instead of building a plant, is utility concerns over the treatment of PPAs in credit scores, such as those calculated by S&P, Fitch, and Moody's. In this memo, this phenomenon will be referred to as debt imputation or debt equivalency.

PacifiCorp states how important the treatment is to them in their application for the Power Cost Adjustment Mechanism (PCAM):

> "In response to the increased risk borne by regulated utilities participating in wholesale energy markets, the major credit rating agencies have been imputing debt on company balance sheets for long-term power purchase agreements ('PPAs'). This debt imputation impacts the credit ratio of a company and, in some cases, may contribute to a credit downgrade."[1]

[1] *See* Oregon Docket UE 173, PPL/100, Omohondro/3.

PacifiCorp points to a S&P report[2] in which the agency states that PacifiCorp's exposure to the markets for power resulted in a negative outlook. Additionally, S&P states that they have an ongoing concern due to the lack of an automatic adjustment to recover purchased power costs.

A 2005 Electric Power Supply Association (EPSA) report[3] included the general views on imputed debt of the three ratings agencies:

1) The rating agencies all intend to continue assigning debt equivalency amounts to PPAs.
2) They justify doing so on the basis that PPAs expose the buyer to risk that the ordinary balance sheet does not capture, apparently reflecting a view that cost recovery for longer-term PPAs is less certain than cost-recovery for a long-lived utility-owned plant.
3) They consider the time lag between the execution of a PPA and the time of cost recovery to be a significant issue, again because of uncertainty surrounding eventual cost recovery.
4) In their opinion, the imputation of debt to PPAs is not intended to question the quality of the seller, but rather to capture the exposure that otherwise doesn't show on the buyer's balance sheet.
5) They assume that the assignment of debt equivalence is not to be seen as a negative penalty on the PPA (unless it is specifically noted as such), but rather as an adjustment.
6) Except in extreme cases, debt equivalency is not to be viewed as questioning the concept of PPAs generally or the efficacy of PPAs as a resource planning tool.
7) They assume that state regulators may choose to adjust debt/equity ratios to equalize the impact of PPA debt equivalencies and, in discussions, had no objections to regulators adopting this approach.
8) Finally, and in many ways most important, all three agencies agreed and assumed that PPAs would continue to be an important way for utilities to acquire generation as part of a balanced power supply portfolio approach. All suggested in these discussions that such balance in the utility's supply portfolio would be reflected in its credit ratings.[4]

Other states have recognized that debt equivalency is an important issue. For example, California adopted a process in 2004 in which debt equivalency would be considered as part of the resource selection process.[5] The CPUC recognized that "…as imprecise and subjective as it may be, DE is a real cost that needs to be considered when evaluating bids from a PPA vs. a utility-owned resource."[6]

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[2] *See* UE 173, PPL/101.
[3] *See* "Electric Utility Resource Planning: The Role of Competitive Procurement and Debt Equivalency." Prepared by GF Energy for EPSA. http://www.epsa.org.
[4] *See* EPSA. Pages 15-16.
[5] *See* California PUC Decision 04-12-048, Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, December 16, 2004.
[6] *Ibid*. Page 144.

To start, the S&P imputation methodology, which was identified in OPUC staff's 2005 memo,[7] is the starting point for a calculation of the cost of debt imputation.[8] The five steps of the methodology are:

1) Calculate the annual capacity payments that have to be made under the contract;[9]
2) Find the net present value (NPV) of the required payment stream discounted at 10%;
3) Apply a factor to determine what to impute as debt on the balance sheet and multiply the contract's NPV by that factor – the result is the PPA debt equivalency;[10]
4) Impute an associated interest expense of 10 percent by adding 10 percent of the debt equivalent amount to reported interest expense to calculate interest expense ratios;
5) Add the debt equivalency amount to the actual amount of debt shown on the utility's balance sheet and calculate an adjusted debt amount and an adjusted interest expense amount, both of which are used to calculate the following:
    a. Debt as a percentage of total capital;
    b. Funds from operations to debt;
    c. Pretax interest coverage; and
    d. Funds from operations coverage.[11]

The CPUC decided that the 30% factor used for California utilities was too high to be reasonable and fair to all PPAs in the comparison process against utility-owned resources. Instead, the CPUC decided on a risk factor of 20% for all resource types.[12] The CPUC also decided that the investor-owned utilities will need to demonstrate, on a total portfolio basis, the debt equivalency impacts of the PPAs in a Cost of Capital proceeding.[13]

Not all who have researched the issue believe that there is evidence that PPAs increase a utility's cost of capital. A 1994 study conducted by the Energy Information Administration concluded that the use of both capital asset pricing model and discounted cash flow cost of capital calculation methods failed to definitively provide evidence that PPAs increase a utility's cost of capital.[14] Additionally, a 1994 report from

[7] See staff's opening comments, Docket UM 1182.
[8] S&P only considers PPA contracts of more than three years.
[9] S&P does not capitalize the energy component of the contract. In contracts where the capacity and energy components are not broken out separately, S&P uses half of the fixed payment as a proxy for the capacity payment.
[10] S&P uses an arbitrary factor between 10%-75% of the NPV. The factor is proprietary and heavily influenced by S&P's perception of the likelihood of the utility's ability to receive a timely recovery of the PPA costs.
[11] See staff's 2005 memo and pages 30-31 of EPSA.
[12] *See* CPUC. Page 145.
[13] *Ibid*.
[14] *See* "Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities," report

Lawrence Berkeley Laboratory found that they could not detect any evidence to support the debt-equivalence hypothesis.[15]

Two other circumstances should also be recognized when looking at PPAs and debt imputation:

1) Even though there may be a level of credit risk when entering into the PPA contract, the operating costs of a utility-owned resource vs. the PPA and the option value of the contract itself should be taken into consideration. The credit risk may be negated to an extent by the reduction in operating costs the utility incurs because they chose a PPA instead of building a plant.
2) Staff's 2005 memo states that, at the time, staff was not aware of any cases in which a company had their credit rating downgraded due to entering a PPA. The rating process considers the future prospects of all material issues that affect a company, including other liabilities such as pensions and asset revaluations.

Staff addressed this issue as it relates to S&P in a 2005 memo by Bryan Conway. Staff recommended that if the Commission wishes to take action to mitigate the impacts of a PPA on a company's balance sheet, the Commission can:

1) Increase the frequency of rate cases, which would reduce the uncertainty caused by regulatory lag;
2) Utilize a resource valuation mechanism process coupled with deferred accounting, which would decrease the likelihood of less than full and timely recovery; and
3) Securitize the capacity payments of a PPA to minimize the likelihood of less than full and time recovery of PPA expenses.[16]

Staff has further explored some possible options related to items 2 and 3. It may not be practical to increase the frequency of rate cases. However, staff has identified one potential option tied entirely to the process of regulation which may serve as an acceptable substitute to going through an entire rate case solely to ensure cost recovery for a PPA contract.

The second potential barrier to the purchase of PPAs is the counterparty risk involved in entering into a PPA contract. By entering into a PPA, a utility is relying on another entity for certain amounts of power at certain prices. If the entity does not fulfill its obligations to the utility, the result is potentially costly to both the utility and to customers, especially if this failure occurs during a period of prices significantly higher than those in the

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prepared by the Energy Information Administration, June 1994. (DOE/EIA-0580; http://www.eia.doe.gov/cneaf/electricity/pub_summaries/finance.html).

[15] *See* Edward Kahn, Steven Stoft, and Timothy Belden, "Impact of Power Purchases from Nonutilities on the Utility Cost of Capital," Energy and Environment Division, Lawrence Berkeley Laboratory, March 1994 (LB-34741; UC 350).
[16] *See* Bryan Conway and Thomas Morgan's memo to Lee Sparling, June 6, 2005.

contract. History has shown that this risk is real, as independent power producers are an industry marked with instability and the bankruptcies of some of its largest players.

The third potential barrier to the purchase of PPAs is that utility-owned power plants earn a return as part of the utility's rate base, whereas PPAs do not. This issue is addressed by the mechanisms discussed under Option No. 4.

The final potential barrier to the purchase of PPAs is the concept of empire building, in which a utility may desire to accumulate assets for reasons other than providing power to customers on a least-cost basis. This could range from a company simply preferring to have steel in the ground to the desire to grow a utility by leaps and bounds, as was the case with Ontario's Hydro One, which purchased almost 100 municipal distributors in order to expand its system.

Using the assumption that the build-vs-buy bias does exist, staff has identified three potential regulatory regimes for the examination of regulatory treatments:

1) Reduction of regulatory risk only;
2) Monetary incentives; and
3) Elimination of rate base.

Regime 1: Reduction of Regulatory Risk Only

The easiest factor for the Commission to control in the elimination of a build-vs-buy bias is the Commission's own process for the review and approval of PPAs and subsequent utility cost recovery.

Option No. 1: Expedited PPA Prudence Review and Allow Dollar-for-Dollar Cost Recovery

The implementation of this option should be fairly uncomplicated due to its planned expediency and guarantee of cost recovery for the contract. Under current statutes, this option is best implemented using the resource rate plan (ORS 757.212) due to its relative expediency and its ability to secure the approved costs and rates associated with a particular resource (ORS 757.212(8).)

The dollar for dollar recovery should also address the debt imputation issue because the guaranteed recovery of costs reduces the risk level of the contract. A 2005 EPSA report[17] states that one factor that can tighten the link between debt equivalency and the credit rating is when a utility's regulatory "regime" does not allow timely cost recovery.

The recovery process does not necessarily involve any deadbands or a sharing mechanism, though these could be implemented. This process may also provide an

[17] *See* "Electric Utility Resource Planning: The Role of Competitive Procurement and Debt Equivalency." Prepared by GF Energy for EPSA. http://www.epsa.org. Page 43.

incentive for the utilities to enter into least-cost contracts, as the Commission will have an immediate opportunity to investigate and approve the contracts.

Regime 2: Monetary Incentives

The proposed Regime 2 options differ from the Regime 1 option in that a utility, in addition to recovering the costs of the PPA contract, has the opportunity to earn additional money depending on regulatory treatment and contract performance. These options address the opportunity cost of purchasing a PPA instead of building a plant.

Option No. 2: Equity Offsets

S&P has identified an authorization of return on the amount of additional common equity needed to offset the debt equivalency of a PPA as one method regulators can use to recognize the cost of debt equivalency.[18] Simply put, recognizing the imputed debt from the PPA will cause a utility's debt-equity ratio to change. The common equity offset would be an addition to the common equity that would restore the authorized debt-equity ratio to the approved ratio. The effect of this addition would be a slight upward movement in the overall authorized rate of return.

Option No. 3: PCAM Mechanism

This option is currently being considered in Docket UE 173 and Docket UE 180. As far as the issue of debt imputation is concerned, the mechanism essentially gives the company the ability to recover power costs, including PPAs, in a more timely manner than rate cases would.

The proposed PacifiCorp mechanism would share variations in the adjusted actual net power costs from the baseline forecast net power cost in rates (with the exception of qualifying facility costs.) The company has also included bands around the baseline that set different levels of sharing.

PGE has also proposed a recovery mechanism, the Annual Power Cost Variance tariff, in Docket UE 180, which is currently being considered by the Commission.

Option No. 4: Inclusion of PPA Contracts in the Rate Base

This proposed option is perhaps the most unconventional of all the options, as there is little to no literature on the inclusion of PPA contracts in the rate base. An informal survey of regulators and utility staff who attended a Denver PBR training resulted in no knowledge of instances of PPA inclusion.

When analyzed in its simplest form, the inclusion of PPA in rate base seems reasonable. A utility is faced with the choice of building a plant or buying a PPA. If

[18] *Ibid*. Page 45.

there is no difference in the cost between the two options,[19] the utility probably chooses to build the plant because, all other things equal, the only benefit missing with the purchase of a PPA is the return to be made.[20] It would seem obvious then to pull the two options into equilibrium by allowing the inclusion of PPAs into the rate base.

However, allowing a PPA to unconditionally be included in rate base can only harm customers. Unconditional inclusion provides an disincentive to the utility to control the cost of the PPA. This is because the higher the price of the PPA power, the more return the utility will make on that contract.

Staff has identified two potential methods for controlling the incentives provided to the utilities while allowing a return on all or a portion of the PPA contract.

1. **Contract Pre-Payment with Prudence Review.** With this method, the utility pre-pays the entire amount of the contract and that amount is capitalized and included in rate base for the length of the contract. It would also be reasonable to determine the amount of the contract that the ratings agencies believe is fixed, and have the utility pay that amount up front. The prudence review would be performed to ensure that the utility has entered into contract with just and reasonable prices, as this method does not directly confront the utility's incentive to enter into unrealistically high-priced contracts. One key to successful implementation of this method is the review of the contract terms, because the method provides an incentive to the company and IPP to sign a deal for as long a term as possible in order to keep the contract in rate base.

2. **Benchmarking.** With this method, the contract is benchmarked against a target and rewards the utility when the contract benefits customers. This method provides the utility with an incentive to enter into lower-priced contracts, as higher-priced contracts are less likely to beat the market. The utility collects the value of the contract either way, but the chance of earning a return is tied to how low the contract prices are. Because a PPA can have fixed or indexed pricing, there are two implementations of this method:

    a. **Fixed Prices Benchmarked Against the Market.** This implementation would compare on a daily, monthly, or annual basis the fixed price of the contract with relevant market prices. If the contract is lower than the market, then the utility earns a return on the difference. If the contract is higher than the market, the utility does not earn a return.

    b. **Indexed Prices Benchmarked Against Avoided Cost Rates.** This implementation would compare on a monthly or annual basis the indexed prices of the contract with the utility's avoided cost rates. If the contract is

[19] With the exception of the timing of the payments.

[20] However, if the rate of return is set correctly there is no additional profit to be made, as the return will cover the utility's cost of financing. Any profit may most likely be tied to the utility's ability to issue debt at a cost lower than the Commission has approved.

lower than the avoided cost rates, then the utility earns a return on the difference. If the contract is higher than avoided cost rates, the utility does not earn a return. One option for this implementation is to use the Gas Market Method avoided cost pricing methodology for the comparison. Under this methodology, the energy portion of the avoided cost rate follows the monthly movement in the natural gas market. As a result, the return for the utility is essentially being earned on the ability of the market-clearing power plant to operate more efficiently than the utility's avoided plant.

If a utility chooses to enter an index-priced PPA and hedges the PPA, perhaps with a fixed-for-float swap, there should be some discussion as to whether the contract is treated as a fixed contract or excluded from the mechanism altogether.

Option No. 5: Generation Incentives

One way to provide incentives to the utilities for procurement goals is to provide a reward to the rate of return. An example is the group of incentives that make up the Con Edison generation incentive. The group of incentives includes:

1) One basis point for every 100 MW hedged through bilateral contracts;
2) One basis point for every 50 MW of added non-ConEd in-city electric generation requiring significant interconnection work; and
3) Up to two basis points for substantial progress in achieving price and price volatility mitigation.[21]

Additional incentives include conservation and technology incentives.

Regime 3: Eliminating the Rate Base

One way to eliminate any bias that favors building a power plant to put in rate base is to eliminate rate base altogether through moving the utility away from cost of service regulation.

Option No. 6: Price Cap Regulation

Price cap regulation is generally brought up in discussions of ways to get utilities to cut costs and ultimately bring down rates. One facet of moving to this form of regulation from cost of service is that the rate base is, for all intents and purposes, eliminated. Because the rate base is eliminated, there is no incentive for a utility to choose to build over buy solely because they earn a return on the plant. If buying power via a PPA is cheaper than building a plant, the utility should choose to buy the PPA. It should be noted that this form of regulation is most popular in areas that have been deregulated

[21] See "Performance-Based Regulation" notes, EUCI Conference, Denver, CO, April 6-7, 2006.

and the utilities divested of their generation assets (e.g., Maine, California, United Kingdom.)

The general formula for price cap regulation is:

$$P_t = P_{t-1}(\Delta Esc – X – s) + z + G$$

Where:
P_t = the price in new time period t
P_{t-1} = the price in the previous time period
ΔEsc = the change in the escalation index
X = productivity factor
s = stretch factor
z = adjustment for unforeseen events
G = optional factor for large incremental investments

The escalation index is generally either the Consumer Price Index (CPI) or the Gross Domestic Product Price Index (GDPPI.)

The productivity factor reduces the escalation to account for improved productivity and is derived from calculations of Total Factor Productivity.[22] In theory, the X is initially set high (resulting in lower prices) in order to incent the utility to cut costs. As the utility becomes more efficient, the X factor can be reduced until ultimately rates escalate with inflation.

The s factor is a “consumer productivity dividend,” which is supposed to reflect an expected difference between future and projected productivity growth. Its use has been very subjective, and if the X factor is set correctly the s factor is not needed.

The z factor adjusts for unforeseen events beyond the utility’s control, such as tax increases or storm damage.

The G factor is an optional factor for large incremental investments, such as power plants or PPAs.

While the use of price cap regulation levels the playing field for purchased contracts and utility-built resources, this form of regulation may not be appropriate for PacifiCorp and PGE. Many of the companies that are under the price cap regime have either divested their generation assets or have a declining rate base. This can mean that there are fewer rate shocks due to capital investment, because eliminating the rate base removes the ability to capitalize large investments. Because PGE and PacifiCorp are both in build stages right now, staff does not prefer this option.

[22] Total Factor Productivity is the ratio of an output quantity index to an input quantity index and measures the efficiency with which firms convert production inputs into outputs.