ORDER NO. 05-1261

ENTERED 12/21/05

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UE 165/UM 1187

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| PORTLAND GENERAL ELECTRIC COMPANY | ) | |
| | ) | |
| Application for a Hydro Generation Power Cost Adjustment Mechanism, (UE 165) | ) | ORDER |
| | ) | |
| and | ) | |
| | ) | |
| Application for Deferral of Costs and Benefits Due to Hydro Generation Variance. (UM 1187) | ) | |

DISPOSITION: STIPULATIONS REJECTED; DOCKETS TO REMAIN OPEN

**Introduction**

On May 18, 2004, pursuant to ORS 757.210, Portland General Electric Company (PGE) filed with the Public Utility Commission of Oregon (Commission) Advice No. 04-11, revising Tariff Sheet Nos. 1-3 and 100-1 and submitting Original Sheet Nos. 128-1, 128-2 and 128-3 (Docket No. UE 165). Simultaneously therewith, pursuant to ORS 757.259 and OAR 860-027-0300, PGE filed an Application for Deferral of Hydro Generation Variance Costs and Benefits (UM 1187 Deferral Application).

PGE proposed to include the Hydro Generation Adjustment (HGA) in the tariff rate design, which would track the difference between the actual and assumed hydro generation in megawatt-hours (MWh) used to set rates for the year determined by month for both on- and off-peak periods, apply various marketplace index effects[1] and utilize a $2.5 million "deadband" under which fluctuations would not be part of the HGA.[2] To implement the HGA, PGE proposed that changes outside of a deadband would be accumulated in a balancing account and no rate changes would be made unless the account was plus or minus $20 million, with the account balance being amortized over three years with appropriate credits or charges to customers' bills. Interest would accrue

[1] "The difference in hydro generation is priced at the monthly average on- and off-peak Mid-C index price, adjusted for incremental wheeling costs and losses." PGE Advice No. 04-11, p. 3.
[2] *Id.*

on the balancing account at the rate approved for PGE's cost of capital, and PGE would make annual filings with the Commission regarding the account.[3]

The three stated objectives were "to share with our retail customers the true value and cost of these hydro-electric generating resources…on an ongoing basis"; to utilize "a methodology that is objective, easy to understand and simple to apply;" and "to minimize the rate fluctuations associated with sharing the value and cost with customers."[4] PGE also noted that its pending application for deferral of excess power costs for 2004 in Docket UM 1128 contained some costs sought in the Deferral Application and indicated its intention that all appropriate adjustments be made to preclude the double capture of costs.[5]

On July 6, 2004, the Commission, by Order No. 04-373, suspended the tariff sheets filed in Advice No. 04-11 to allow for further investigation of the proposed HGA mechanism and delayed its decision on authorization of PGE's request to defer the costs or benefits associated with the HGA until the time at which the mechanism might be approved. Pursuant to PGE's motion for a standard protective order filed July 16, 2004, Order No. 04-406 was entered on July 22, 2004.

On August 6, 2004, a Notice of Intervention was filed by the Citizens' Utility Board (CUB) and a Petition to Intervene was filed by the Industrial Customers of Northwest Utilities (ICNU). The CUB Notice of Intervention was recognized, and the ICNU Petition to Intervene was granted by a ruling of the Administrative Law Judge (ALJ) on October 1, 2004. Over the course of the proceeding, there were numerous conferences and changes to the schedule agreed upon by the parties and adopted by the ALJ.

PGE filed direct testimony and exhibits on November 17, 2004, and replacement and supplemental direct testimony on November 24, 2004, and December 27, 2004, respectively. By Order No. 04-760, signed by the Chief ALJ and entered December 29, 2004, the tariff sheets were further suspended.

On February 14, 2005, opening and direct testimony was filed by CUB, ICNU and the Commission staff (Staff). CUB filed replacement pages for its opening testimony on February 24, 2005. ICNU filed rebuttal testimony on March 15, 2005. By Order No. 05-161, signed by the Chief ALJ and entered April 1, 2005, the tariff sheets were further suspended until October 1, 2005.

On December 30, 2004, PGE filed a second Application for Deferral of Costs and Benefits due to Hydro Generation Variance docketed as UM 1187. Neither Staff nor either of the intervenors supported the PGE HGA proposal.

---

[3] *Id.*, pp. 3-4.
[4] *Id.*, pp. 1-2.
[5] *Id.*, p. 5.

**The Stipulations**

PGE, Staff and all intervenors in this docket held settlement conferences in this docket on December 8, 2004, March 3, 2005, and March 14, 2005. As a result of those settlement discussions, on April 11, 2005, PGE and Staff filed a stipulation (the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM) Stipulation) in Docket UE 165 and a separate stipulation in Docket UM 1187 (the Deferral Stipulation). PGE and Staff filed Direct Testimony and Exhibits in support of the two stipulations on April 18, 2005. PGE also filed rebuttal testimony and exhibits on April 18, 2005. ICNU and CUB filed testimony and exhibits relative to the Stipulations on June 2, 2005. PGE and Staff filed surrebuttal testimony and exhibits on July 21, 2005.

A hearing was held on August 9, 2005. Counsel for PGE, Staff, CUB and ICNU all filed appearances at the hearing. Cross-examination was waived by the parties with respect to all witnesses except for Staff Witness Maury Galbraith who was cross-examined by ICNU counsel. Opening Briefs were filed by all parties on September 9, 2005, and Reply Briefs on September 21, 2005.

## DISCUSSION

The regulatory treatment of hydro power variations can significantly affect PGE's earnings. While most hydro-electric generating capacity is owned and controlled by the federal government, PGE is one of but a few investor-owned utilities with a significant amount of hydro-electric generating capacity, accounting for 27 percent of PGE's total capacity and 25 percent of its average energy portfolio. Forty percent of the hydro generation capacity comes from relatively older assets owned by PGE; the rest is obtained under contracts on which PGE earns no returns.[6] Historically, PGE and the Commission have used a 59-year average for hydro generation in setting rates. Given the variability of rainfall, the average and actual water flows seldom match. PGE has asserted that the risk of variability is hard to model because weather assumptions are difficult to make. Added to the variability risk of water conditions are the risk perceptions of the marketplace, which also have a profound impact on pricing; *i.e.*, if market investors believe that future hydro conditions may be poor, the forward price of energy contracts will increase regardless of the current balance of supply and demand.[7]

**The Stipulations, Joint Testimony and PGE and Staff Briefs in Support Thereof**

PGE and Staff entered into two stipulations seeking implementation of a temporary automatic adjustment tariff applicable to Calendar Years 2005 and 2006. A copy of the SD-PCAM Stipulation in Docket UE 165 is attached to this Order as Appendix A. A copy of the Deferral Stipulation in Docket UM 1187 is attached as Appendix B.[8] Staff and PGE agree that the Stipulations are in the public interest and will produce rates that are fair, just and reasonable.

---

[6] PGE Advice No. 04-11, p. 2.
[7] *Id.*
[8] The SD-PCAM Stipulation and Deferral Stipulation utilized a number of concepts and descriptive acronyms identified during the hearing (tr. p. 4) and discussed in this Order. Among these are the following: BPC for Base Power Cost; EVPC for Expected Value Power Cost; MONET for the PGE

The mechanism in the SD-PCAM Stipulation differs substantially from the HGA mechanism proposed by PGE. The SD-PCAM tracks the annual difference between the Base Power Costs established in PGE's RVM proceedings and Updated Power Costs determined by using (1) the actual hourly hydro generation, (2) actual market electricity prices using the hourly shape of the Dow Jones Mid-Columbia Hourly Index prices to shape Dow Jones Mid-Columbia Daily Index on- and off-peak prices to hourly prices, and (3) actual gas prices using daily index prices. According to Staff and PGE's witnesses, only part of the SDCV will result in a change to rates, subject to an earnings test.[9]

The SD-PCAM addresses earlier concerns raised by Staff, CUB and ICNU that the HGA mechanism did not take into account how hydro conditions affected the use of PGE's natural gas-fired plants where there were also increases in the spread between the market prices for gas and electricity.

The SD-PCAM also made the deadband asymmetric: where the annual SDCV is positive, PGE shareholders would absorb the first $15 million dollars of cost due to a poor hydro year; when the annual SDCV is negative due to good hydro conditions, PGE shareholders would keep only the first $7.5 million before cost-of-service reductions accrued. Deferral of SDCV outside the deadband would be limited to 80 percent.

Under the SD-PCAM Stipulation, the recovery of costs from customers via the deferral account discussed *infra* would be limited by an annual earnings test providing for a 10.5 percent return on equity (ROE) for 2005 and 2006. Recovery of any deferral amounts which result in PGE earning an ROE that exceeds 10.5 percent on a regulated basis would be written off.[10] Refund of any deferred amounts would be limited to those that result in PGE earning no less than a 10.5 percent ROE on a regulated basis. All other elements of the earnings test would derive from Commission decisions in PGE's last general rate case.[11] While the earnings test would provide a measure of reasonableness to the process, it would not guarantee PGE would earn its authorized ROE. The incremental impact of the SD-PCAM would not, in the view of the Joint Testimony witnesses, push PGE's ROE either up or down to an unreasonable level.[12]

A final feature of the Stipulations is that PGE would fund consulting services: a $100,000 feasibility study that would provide information on the issues involved in developing expected value power costs.[13]

---

computer model that forecasts power costs for ratemaking purposes; NVPC for Net Variable Power Cost; SDCV for System Dispatch Cost Variance; SD-PCAM for System Dispatch Power Cost Adjustment Mechanism; RVM for Resource Valuation Method; and WACOG for the Weighted Average Cost of Gas.

[9] UE 165-UM 1187/Staff-PGE/100, Galbraith-Tinker/2-3. (Joint Direct Testimony.) The SD-PCAM implementation principles and methodology are described at pp. 3-5.

[10] *Id.*, pp. 5-6.

[11] *Id.*, p. 6.

[12] *Id.*, pp. 6-7.

[13] *Id.*, p. 7.

**ICNU and CUB Responses to the Stipulations**

CUB and ICNU both advocate rejection of the Stipulations by the Commission. Their objections, to which the Staff and PGE responded, relate to the following four issues:

**1. Retroactive Ratemaking.** CUB asserts that "the Stipulation attempts to take the place of, or piggy-back upon, the 2005 Hydro Deferral that PGE filed in UM 1187. It does this by making the PCA, which could not be adopted by the Commission earlier than September 2005, retroactive to January 1, 2005. However, the PCA would be a rate mechanism all by itself, regardless of how the Commission treats PGE's 2005 deferral application."[14] Furthermore, in CUB's view, the Stipulation confuses deferral, which statutes provide for, with "a form of Automatic Adjustment Clause under ORS 757.210, which does not provide any explicit exceptions to the general prohibition on retroactive ratemaking. PGE and Staff should not be allowed to violate Commission policy by inappropriately confusing statutory devices."[15]

ICNU asserts that the Stipulation allows for deferral of costs unrelated to hydro variations, and is thus "broader in scope than the hydro-only mechanism the Company originally requested…. Regardless of whether the Commission has discretion to adopt a different method to establish a 'hydro only' deferred account as originally requested by PGE, the Commission cannot authorize a deferred account that is not 'hydro only' unless the Company has requested such a deferral." ICNU argues that the SD-PCAM is itself the problem because it takes gas prices and wholesale power prices into its design.[16]

Staff asserts that ICNU's claim that the costs go beyond hydro variability is incorrect and that the impact of hydro variability on PGE system operations is complex. Even assuming, *arguendo,* that not all the costs were properly classified, ORS 757.259(2)(e) still authorizes the Commission to defer identifiable revenues and expenses and provide for their deferral "to match appropriately the costs borne by and benefits received by ratepayers." If PGE were "simply tracking the megawatt-hour variation in hydroelectric generation with no consideration for concurrent changes in wholesale electricity and natural gas prices, [PGE] would likely not obtain a match between the costs and benefits of hydro generation variation."[17]

PGE states that the Commission "has ample authority to approve the SD-PCAM" and that the proposed deferral meets the statutory authority and that "the new methodology will actually be *more* effective in matching the 'costs borne by and benefits received by ratepayers….'" "PGE's deferral application is no different from any other deferral application in this respect. It would constitute retroactive ratemaking, but is permissible because it meets the statutory standard."[18] PGE also rejects the claim that the SD-PCAM and related hydro deferral proposal include costs unrelated to hydro

---

[14] CUB Opening Brief, p. 3.
[15] *Id.*, p. 4.
[16] ICNU/300, Falkenberg/7-9.
[17] Staff Opening Brief, p. 7.
[18] PGE Post-Hearing Brief, pp. 8, 12. Emphasis in text.

variations. Rather, they take into account how hydro conditions could affect the use of PGE's thermal plants, particularly PGE's natural gas-fired generation.[19]

**2. The SD-PCAM Deadband.** CUB argues that the -$7.5 million/ +$15 million deadband "is not appropriately sized, it diverges from past Commission decisions on deferral mechanisms, and it inexplicably deviates from Staff's otherwise consistent position on deadbands both in this, as well as other dockets." The shareholders should absorb normal risk of 250 basis points or $40 million and are thus being overcompensated because the deadband provides for a lesser risk.[20]

ICNU argues that the Stipulations were supported by very little testimony or other evidence and the settlement was therefore premature, a solution resembling nothing proposed by any of the parties; there is no evidence that the deadband would ensure revenue neutrality, despite Staff assertions. Further, as CUB noted, the sharing mechanism is far more generous than those adopted in the past.[21]

Staff claims that the earlier decisions "are inapposite because the sharing mechanisms were for all components of net variable power costs. In contrast, the SD-PCAM tracks changes in NVPC associated only with deviation in hydro conditions, wholesale electricity prices and natural gas prices…. [I]t is appropriate to have a smaller deadband."[22]

PGE also argues that the SD-PCAM deadband is appropriate, stating that the 250 basis point spread advocated by CUB and ICNU "is nothing more than reference to previous deadbands, which were adopted for much broader power cost deferrals…. CUB and ICNU also fail to recognize that the SD-PCAM is a narrow, focused mechanism, not a broad power cost mechanism."[23]

**3. Staff's Position in UM 1071.** CUB and ICNU both argue that Staff has taken a position inconsistent with that which it staked out in UM 1071. Citing Order No. 04-108, page 5, CUB asserts that "Staff took the position that PGE's application for a deferral should be denied in part because the hydro cost did not deviate sufficiently from the variability built into rates," recommending that the Commission include an alternative that took the $17.5 million hydro-related cost and apply a $39.6 million deadband. Recently, Staff also recommended a 250-basis point deadband for PacifiCorp's PCA.[24]

ICNU also asserts that the Commission's UM 1071 decision denying PGE's deferral request was well-founded because it recognized that the hydro year on which PGE based its application was a stochastic risk, being only a 1 in 4.5-year event and part of the process of setting normalized rates.[25]

---

[19] *Id.*, p. 9.
[20] CUB Opening Brief, pp. 5-6.
[21] ICNU/300, Falkenberg/23-25.
[22] Staff Opening Brief, p. 10.
[23] PGE Post-Hearing Brief, p. 17.
[24] CUB Opening Brief, p. 7.
[25] ICNU/300, Falkenberg/15-18.

Staff asserts that the Stipulations in UE 165 and UM 1187 must be looked at in a common context, not separately. The Stipulations were but one step toward the implementation of a long-term solution. Staff sought to encourage the use of Expected Value Power Cost modeling to inform setting the PCA mechanism deadband at the boundary between normal and extraordinary hydro events.[26]

PGE also asserts that the SD-PCAM is consistent with the Commission's decision in UM 1071 and that the situations are not analogous. "The deferral in UM 1187 is part of a PCA allocating the risks and benefits of hydro variability. It is not permanent, but it is intended to be a two-year step leading to a permanent PCA mechanism. The stipulated outcome of UM 1187 is consistent with and implements the directions contained in the UM 1071 Order."[27]

**4. The Design of the PCA Mechanism and the Use of the MONET Model.** CUB asserts that SD-PCAM itself is "replete with theoretical and practical flaws."[28] CUB claims that the mechanism assumes imprudent behavior because it relies on the assumption that in "pricing the replacement power for the lost hydro, PGE would wait until the power is needed and then purchase power on what could be the most expensive—or at least most volatile—market: the day-ahead market…. PGE would never actually take such an imprudent approach…. The difference between the cost incurred by an imprudent utility…and the actual cost that PGE incurs, flows to the Company, which, in effect, reduces or eliminates the already-narrow deadband."[29] CUB also asserts that the PCA mechanism "picks and chooses which costs included are actual and which are modeled when updating power costs." Not including actual replacement cost "flies against the principle underlying the purpose of an appropriate PCA."[30] CUB also faults the SD-PCAM for not using actual load when calculating the power cost variation and, in so doing, "distorts and destroys the conservation incentive."[31] Finally, CUB is concerned that "there is neither the intent nor the possibility of testing the PCA for performance…. [T]he model is not ready to run anything yet, much less set rates."[32]

ICNU states that the SD-PCAM concept was not introduced into the record where "it would have been possible for parties to study it in more detail, and possibly test its validity. Potential flaws and problems in the approach might have been uncovered and perhaps substantial improvements could be made in the methodology."[33] The SD-PCAM goes beyond hydro costs, is unaccompanied by any evidence that demonstrates that the deadband is revenue neutral, and the MONET model is complex and lacking in transparency.[34]

Staff responds to CUB's arguments by noting that "neither ORS 757.210(1) nor ORS 757.259(2) require the use of 'actual costs' as opposed to cost estimation or cost

---

[26] Staff Opening Brief, p. 9; Staff Reply Brief, p. 5.
[27] PGE Post-Hearing Brief, p. 15.
[28] CUB Opening Brief, p. 1.
[29] *Id.*, pp. 8-9.
[30] *Id.*, p. 9.
[31] *Id.*, p. 10.
[32] *Id.*, p. 12.
[33] ICNU/300, Falkenberg/23-24.
[34] *Id.*, pp. 26-28.

approximation." Furthermore, "CUB's position that the power cost adjustment mechanism should be broader than that arrived at by Staff and PGE" is not a flaw, but merely a difference of opinion. "Staff does not believe it is necessary to include updates to load in the SD-PCAM MONET runs to appropriately match costs and benefits associated with hydro variability.[35]

Staff states that, contrary to ICNU's assertions, "the parties have had ample opportunity to conduct discovery on the Stipulations and present their positions regarding the merit of the Stipulations to the Commission…. [I]n addition to participating in the settlement conferences leading to the Stipulations, the intervenors have had approximately four months to investigate the merit of the Stipulations…. Any prejudice that could have possibly been caused to intervenors by the timing of the Stipulations has been cured."[36] Furthermore, ICNU's concerns about being unable to review the SD-PCAM data are unfounded because "amortization of any collection or refund under the SD-PCAM will require a tariff filing and thus, trigger all of the statutory and Commission processes pertaining to tariff filings. The review process will include the ability to examine the MONET model and results…."[37]

PGE asserts that "by using MONET, the power cost modeling tool already employed by PGE to set rates in its RVM, the SD-PCAM creates the forecast the Commission *would have used to set rates* had it known what hydro production would actually be. This mechanism is superior to the simpler method employed by the HGA[.]"[38] PGE later adds that, "while no ratemaking mechanism is perfect, and the SD-PCAM should be considered a stepping stone to a more permanent solution, it is a fair and straightforward way to address this complex issue.[39]

## OPINION

In Docket No. UM 1071, we stated that "a PCA may be an appropriate way of permanently allocating risks and benefits of hydro variability between shareholders and ratepayers."[40] We continue to believe a mechanism to adjust PGE's rates for variations in hydro-related costs should be adopted if it is reasonably designed.

### Design Criteria

We identify four primary design criteria that should be included in a hydro-related PCA. These criteria, addressed separately below, are as follows: (1) Limited to Unusual Events; (2) No Adjustments if Overall Earnings are Reasonable; (3) Revenue Neutrality; and (4) Long-Term Operation.

**(1) Limited to Unusual Events.** We concluded in Docket No. UM 1071 that deferred accounting is not justified for a stochastic risk like hydro availability

[35] Staff Opening Brief, pp. 13-14.
[36] *Id.*, p. 12.
[37] *Id.*, p. 13.
[38] PGE Reply Brief, p. 3. Emphasis in text.
[39] PGE Post-Hearing Brief, p. 5.
[40] Order No. 04-108, p. 10.

unless the event (*e.g.,* actual hydro realized) is extraordinary and the financial impact is substantial. To determine whether an event is extraordinary and has substantial financial impact, the Commission has, in prior cases, examined whether the event impacted the utility's earnings beyond a reasonable range within which the utility should bear the entire cost or benefit of variability. [41]

At the outset, we believe that a hydro-related PCA should include separate standards for the unusual nature of the event and its financial impact. 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.

We believe less extreme events should qualify for recovery or refund through a hydro-related PCA rather than under one-time deferred accounting for two reasons. First, as further discussed below, a PCA should remain in effect for many years, allowing the mechanism to pick up the effects of good and bad hydro conditions over time. In contrast, with a one-time deferral, there is no guarantee that the effects of offsetting events will be reflected in customer rates, so the standard for recovery should be stricter. Second, hydro availability is largely beyond the company's control. In an analogous situation--treatment of differences between actual and forecast gas commodity costs in the annual purchased gas adjustment (PGA)--we have allowed natural gas utilities recovery (or refund) of a portion of all differences; *i.e.,* sharing but no deadband. Therefore, we believe that a more-inclusive standard--unusual, but not necessarily extraordinary, events--should be used for hydro-related PCAs.

**2. No Adjustments if Overall Earnings are Reasonable.** In addition to a deadband around power costs to limit operation of the mechanism to unusual events, a hydro-related PCA should include an earnings deadband around the company's allowed ROE. If earnings are outside this deadband, recovery or refund would be allowed to the perimeter of the range. For example, if the utility's earnings are below the bottom of the range, recovery for poor hydro conditions (as determined through application of the power cost deadband and further sharing between the company and customers) would be allowed up to the bottom of the range.

All discussion of deadbands up until now has focused on a single deadband around expected power costs that was intended to capture both the extreme nature of the qualifying event and its financial impact. The Commission adopted a deadband for recovery of excess power costs equal to a 250-basis points ROE in authorizing deferrals or approving amortization of deferred accounts in several cases.[42] CUB proposes the same deadband for recovery of excess power costs under a PCA in this proceeding.[43] A 250-basis point ROE deadband may be appropriate in a one-deadband

[41] *Id.,* p. 9.
[42] *See, e.g.,* Docket Nos. UM 995 (PacifiCorp), UM 1007 (Idaho Power) and UM 1008/1009 (PGE).
[43] CUB Opening Brief at 2-3. For PGE, a 250-basis points ROE equals about $45 million a year.

approach, but it overstates the range of reasonable earnings in the two-part mechanism (with one deadband on power costs and another on overall earnings) we set forth here.[44]

One other indication of the range of reasonable returns is found in the Commission's ROE decisions. In PGE's last general rate case,[45] the Commission found that one acceptable method produced an ROE range of 10.4 to 11.5 percent. Combining the midpoint of that range with the point estimate from the other accepted approach produced a final range of 10.53 to 10.95 percent.[46] In the last PacifiCorp rate case where cost of capital was not settled, the Commission concluded that the evidence supported a reasonable ROE estimate in the range of 10.5 to 11.0 percent.[47]

These different ranges (+/- 250 basis points for previous deferrals and PCAs and +/- 25-50 basis points in ROE decisions) bracket what we consider to be a reasonable deadband for a hydro-related PCA. On balance, we believe an ROE deadband of +/- 100 basis points would be appropriate for such a PCA.

We recognize that allowing adjustment for unusual events, if earnings are outside this ROE deadband, may cause more frequent and larger rate changes for customers than simple application of a 250-basis point deadband to power cost variations.[48] Adoption of the two-part mechanism outlined here may well shift risks to customers that they have not borne under the sporadic use of deferrals and PCAs in the past. If so, we will consider the reduced risk for the company in setting ROE in future rate cases.

**3. Revenue Neutrality.** We agree with Staff that operation of a hydro-related PCA should not bias the overall expected level of power cost recovery; *i.e.,* the mechanism should be revenue neutral over time.[49] CUB notes that this requires an asymmetric deadband on power costs because the cost of replacement power in poor hydro years outweighs the benefits of additional power in good hydro years.[50]

**4. Long-Term Operation.** As noted above, we believe that a PCA may be an appropriate way of *permanently* allocating the risks and benefits of hydro variability. The first design criterion identified above--that a hydro-related PCA should allow adjustment for conditions that are unusual but not necessarily extraordinary--depends on the mechanism being in effect for an extended period. Furthermore, in order to achieve revenue neutrality, the PCA must be able to operate over the range of varying hydro conditions.

---

[44] In Docket No. UE 115, the Commission authorized an adjustment mechanism with a +/- $28 million deadband for the 15 months beginning October 1, 2001. Order No. 01-777 at 19. It is difficult to compare this deadband to the others cited because it covered variations in energy revenue as well as power costs.
[45] Docket No. UE 115.
[46] Order No. 01-777, pp. 35-36.
[47] Docket No. UE 116, Order No. 01-787, p. 34.
[48] We note that if the company's results of operations are otherwise good enough to produce reasonable earnings under poor hydro conditions, some recovery might be allowed under the conventional approach with a 250-basis point deadband on power costs but not under the two-part mechanism described here.
[49] Staff/100, Galbraith/12.
[50] CUB Opening Brief, pp. 2-3.

**Other Proposed Design Principles.** Finally, we address several basic design principles identified by PGE and supported in general terms by other parties. Other design principles that are suggested by the arguments of CUB and ICNU against the proposed SD-PCAM are discussed in our evaluation of that mechanism below.

PGE suggests that a hydro-related PCA should be designed to provide incentives for good management.[51] Previous deferrals and PCAs have included sharing of impacts outside any deadband, in order to give the company a stake in the outcome and thereby provide it an incentive to keep costs down. Some sharing is appropriate as a way to share the risk associated with hydro variability. But since hydro availability is beyond the company's control, we are doubtful that sharing or any other design of a hydro-related PCA can provide much of a management incentive. The company does have discretion in responding to the variation in hydro production (*e.g.*, through redispatch of other resources), but on balance we do not give high priority to providing incentives in a hydro-related PCA.

PGE also identifies transparency, and rate predictability and stability as design criteria.[52] While these are desirable characteristics, they do not provide much guidance in how to construct an adjustment mechanism and are best used to make close calls between competing proposals.

**Evaluation of the SD-PCAM Stipulation**

Having identified the necessary design criteria for a hydro-only PCA, we discuss how the SD-PCAM fares under the requirements described above. We conclude that the mechanism meets some, but not all, of our standards, and we decline to adopt it.

The power cost deadband in the SD-PCAM ranges from $7.5 million below expected power costs to $15 million above. PGE and Staff provided no evidence on the frequency with which the mechanism would be triggered under the range of hydro conditions (based on the historical record). In Docket No. UM 1071, however, Staff estimated that a hydro year characterized as a 1 in 4.5-year event produced excess hydro-related power costs of $17.5 million.[53] We believe that an upper deadband of $15 million is reasonable for limiting recovery to unusual events, at least in the short-run until further information about likely results under the mechanism can be developed.

The SD-PCAM includes an earnings test but no earnings deadband. The mechanism allows recovery of excess power costs (as measured by the difference in specified MONET model runs and after application of the deadband and 80-20 customer-company sharing) up to PGE's authorized ROE of 10.5 percent. Refund of qualifying power cost savings in good water years would be allowed down to that earnings level. As a result, the SD-PCAM could give PGE recovery of excess power costs even when its earnings are at a level we consider reasonable; *i.e.*, between 9.5 and 10.5 percent ROE.

---

[51] PGE/100, Lesh/12.
[52] *Id.*, pp. 10-11.
[53] Order No. 04-108, p. 9.

The stipulated mechanism has an asymmetric power cost deadband and is intended to be revenue-neutral.[54] However, PGE and Staff provided no evidence that it would be revenue-neutral over the range of hydro conditions.[55]

The SD-PCAM clearly does not meet the criterion that it should be a long-term mechanism. The SD-PCAM only applies to 2005 and 2006. It is intended to be a two-year step leading to a permanent PCA, and, to that end, the Stipulations provides for research on the distribution of power costs that can be used to design the new PCA.[56] But there is no guarantee that a PCA will be in place after 2006.

CUB and ICNU raise several other concerns about the SD-PCAM. Even though we are not adopting the Stipulations, our views on these issues may help the parties craft an acceptable hydro-related PCA.

Most of the concerns expressed by CUB and ICNU deal with the approach used to determine the effect on power costs of hydro variations. As described in the Stipulations, the power cost effect would be calculated as the difference between the baseline MONET run used to set base rates and the same MONET run with actual, instead of forecast, hydro output and market prices for electricity and natural gas. CUB argues that this approach would have PGE replace hydro shortfalls on a day-ahead basis, a short-term approach the company would not employ under drought conditions.[57] But we agree with Staff that separating out the effect of specific events (good or bad hydro in this case) requires modeling and approximation. As Staff notes, parties have come up with dramatically different estimates of the effect of plant outages or hydro shortfalls in other cases.[58] Since advance purchases to replace hydro shortfalls may wind up costing more or less than spot purchases, we are not convinced that the modeling assumption criticized by CUB biases the results of a long-term PCA.

ICNU argues that PGE should use day-of instead of day-ahead electricity prices in the power cost calculation.[59] PGE proposed use of day-ahead prices to match up with natural gas data, which is only available on a day-ahead basis, arguing that it is necessary to use consistent data to model the redispatch of resources when hydro varies.[60] We agree with PGE that accurate modeling of plant dispatch requires a consistent set of electric and gas prices.

CUB also believes that the effect of variations in load (actual versus forecast) should be recognized in the calculation.[61] Staff responds that this is not a flaw

---

[54] Staff/300, Galbraith/8-10.
[55] In addition, ICNU argues in its Reply Brief at pages 20-21 that the earnings test undermines any revenue neutrality produced by the asymmetric power cost deadband. ICNU's argument may apply to a symmetric earnings band like the one described above (+/- 100-basis points ROE). Because we do not adopt the stipulated SD-PCAM here, we do not need to decide whether ICNU is correct, but the issue should be addressed in any future filing of a hydro-related PCA[0].
[56] PGE Opening Brief, pp. 15-16; Staff Opening Brief, p. 9.
[57] CUB Opening Brief, pp. 8-9.
[58] Staff/400, Galbraith/3-4.
[59] ICNU/300, Falkenberg/32-34.
[60] PGE/1100, Lesh-Tinker/14-15.
[61] CUB Opening Brief, pp. 9-11.

but a matter of judgment about the scope of the mechanism and that adjusting for loads goes beyond trying to deal with hydro variability.[62] We agree with Staff.

We note that the SD-PCAM, with the modeling approach used to calculate hydro-related power cost variations, does not provide any incentives for good (or bad) management. The calculation depends on actual versus forecast hydro and market prices for electricity and gas, not on any variables within PGE's control. We consider this an acceptable consequence of trying to separate out the effects of hydro variations and the resulting redispatch of resources. In a PCA like this, the results of the model runs should be subject to audit, but no prudence review of the company's actions in managing power costs is necessary.

ICNU notes that the Stipulation is silent on whether any adjustment would apply to direct access customers and how the adjustment would be collected from qualifying customers (rate spread).[63] Before PGE and Staff agreed on the SD-PCAM, PGE argued that any power cost adjustment should apply to direct access customers (except those who have opted out for at least five years), in order to treat all nonresidential customers the same.[64] Staff believes that the mechanism should not bias customer decisions between direct access and cost of service, which suggests that any adjustment for a particular time period should apply only to the extent a customer was on cost of service during the period.[65] We agree with Staff and expect any future PCA filing to incorporate a provision to that effect. We also expect any such filing to address the rate spread issue and suggest the parties look to past practice on recovery of deferred excess power costs.

CUB and ICNU also raise the issue of "retroactive ratemaking," because the SD-PCAM Stipulation offered on April 18, 2005, to apply to 2005 and 2006, differed substantially from the original HGA proposal. As stated above, we are rejecting the Stipulation. However, we still have before us the UM 1187 deferred accounting application.

Ratemaking principles generally prohibit collecting revenues from current customers to cover costs incurred by previous customers. However, ORS 757.259 provides, in part, for the deferral of costs to be included in later rate proceedings. PGE proposed to use deferred accounts to smooth out the effect of the hydro variance adjustment mechanism on a forward-going basis and broadened its proposal in the UM 1187 filing "to implement the terms of tariff Schedule 128 *or such other allocation of the costs and benefits* of the variance in hydro generation that the commission adopts in UE 165."[66] The language is thus broad enough to enable us to consider the application for deferral of hydro costs without being bound to PGE's original UE 165 HGA or the SD-PCAM.

[62] Staff Opening Brief, pp. 13-14.
[63] ICNU Opening Brief, p. 14.
[64] PGE/700, Kuns/2-3.
[65] Staff/100, Galbraith/12-13, 19-20.
[66] UM 1187 Deferral Application, p. 2. Emphasis supplied.

## CONCLUSION

For the reasons identified above, the Commission concludes that the SD-PCAM Stipulation should be rejected. However, we shall keep these dockets open in the event that PGE wishes to submit to the Commission a hydro-related PCA that meets the design criteria set forth above. In conjunction with such submission, we welcome PGE's proposal with respect to whether the mechanism should cover the 2005 calendar year, under the deferred accounting application in UM 1187, or should begin with 2006. As to the duration of any hydro-related PCA, the mechanism should remain in effect until revised or terminated by the Commission. While our rejection of the SD-PCAM Stipulation relieves PGE of the obligation to fund research on the distribution of power costs, we encourage the company to work with the parties to develop such information.

PGE should work with Staff and the other parties to develop a revised hydro-related PCA. PGE shall file any such proposal no later than February 15, 2006. Staff and Intervenors shall then be permitted to file comments thereon no later than

March 3, 2006, addressing the compliance of the mechanism with this order, as well as whether the mechanism should apply to Calendar Year 2005. We will consider such submissions on an expedited basis, and we encourage the parties to find common ground.

**ORDER**

IT IS ORDERED that:

1. The Stipulations submitted by PGE and Commission Staff, attached as Appendices, are rejected in their entirety.

2. Advice No. 04-11 filed by Portland General Electric Company on May 18, 2004, is permanently suspended.

Made, entered, and effective DEC 21 2005.

**Lee Beyer**
Chairman

**Ray Baum**
Commissioner

**John Savage**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## UE 165

| | | |
|---|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC<br>Application for a Hydro Generation Power Cost Adjustment Mechanism. | )<br>)<br>)<br>)<br>)<br>) | **STIPULATION** |

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE") and Staff of the Public Utility Commission of Oregon ("Staff"). Capitalized terms used in this Stipulation have the meanings ascribed to them in this Stipulation.

On May 18, 2004, PGE filed an Application for a Hydro Generation Power Cost Adjustment Mechanism, requesting approval of tariff schedule 128. Tariff schedule 128 is an automatic adjustment clause under ORS 757.210. PGE sought this tariff to track the costs and value associated with hydro generation assets and contracts.

PGE filed its Direct Testimony in this docket on November 17, 2004. The filing consisted of seven pieces of testimony by eight different witnesses supporting the need for the proposed tariff mechanism. In addition, on December 30, 2004, PGE filed an Application for Deferral of Costs and Benefits Due to Hydro Generation Variance, seeking to defer the costs and benefits caused by hydro generation variance beginning January 1, 2005. That deferral was assigned docket number UM 1187.

Numerous data requests have been propounded and responded to by PGE, Staff and other parties in this docket.[1] On February 14, 2005, Staff and other parties filed Rebuttal Testimony in

1 The Citizens' Utility Board ("CUB") and the Industrial Customers of Northwest Utilities ("ICNU") have also been active participants in this docket. CUB and ICNU have not, however, joined in this Stipulation.

this docket. In that testimony Staff proposed that a temporary mechanism be implemented for calendar years 2005 and 2006, with the anticipation that an ongoing mechanism would be adopted as part of a general rate case and effective beginning in 2007.

PGE, Staff and all intervenors in this docket held settlement conferences in this docket on December 8, 2004, March 3, 2005, and March 14, 2005. As a result of those settlement discussions, PGE and Staff are entering into this Stipulation requesting implementation of a temporary automatic adjustment tariff applicable to calendar years 2005 and 2006.[2] Specifically, Staff and PGE agree to and request that the Commission adopt orders in this docket implementing the following:

STIPULATION

1. For purposes of this Stipulation, Base Power Costs for each year are defined as the costs included in PGE's final RVM MONET run filed in mid-November of the previous year, as updated for cost of service loads and corresponding costs to reflect customer elections made in November.

2. For purposes of this Stipulation, Updated Power Costs for each year will be determined by taking the Base Power Cost MONET run and updating it for the following factors:

a) Actual hourly hydro generation;

b) Actual market electricity prices using daily on-peak and off-peak prices from the Dow Jones Mid-Columbia Daily Electricity Firm Price Index and the hourly price shape from the Dow Jones Mid-Columbia Hourly Electricity Price Index.

---

[2] As set forth below, Staff and PGE agree to support and request an order in docket UM 1187, the hydro deferral filed by PGE, implementing the terms of the adjustment mechanism agreed to in this docket beginning January 1, 2005.

c) Actual market natural gas prices using the Platts GasDat daily index prices for Sumas, AECO, and Malin.

3. The System Dispatch Cost Variance ("SDCV") is the difference between the Updated Power Costs and Base Power Costs. The SDCV will be deferred into a new account, the SDCV Account, subject to the following provisions:

a) If the SDCV is negative (i.e., Updated Power Costs are less than Base Power Costs), then deferral of the SDCV will be subject to a deadband of $7.5 million.

b) If the SDCV is positive (i.e., Updated Power Costs are higher than Base Power Costs), then deferral of the SDCV will be subject to a deadband of $15 million.

c) Eighty percent of SDCV amounts outside these deadbands will be deferred into the SDCV Account.

4. A positive SDCV Account balance may be charged to customers subject to the following provisions. The amount to be charged to customers will be called the SDCV Recovery Amount. An earnings test will be applied to determine the SDCV Recovery Amount:

a) The SDCV Recovery Amount will be limited to amounts that result in PGE earning no greater than the return on equity ("ROE") authorized in its last general rate case, 10.5%, on a regulated basis.

b) All amounts which result in PGE earning an ROE in excess of 10.5% on a regulated basis will not be recovered and may not be carried over to future periods.

5. A negative SDCV Account balance may be refunded to customers subject to the following provisions. The amount to be refunded to customers will be called the SDCV Refund Amount. An earnings test will be applied to determine the SDCV Refund Amount:

a) The SDCV Refund Amount will be limited to amounts that result in PGE earning no less than the return on equity ("ROE") authorized in its last general rate case, 10.5%, on a regulated basis.

b) All amounts which result in PGE earning an ROE less than 10.5% on a regulated basis will not be refunded and may not be carried over to future periods.

6. The earnings test shall be subject to the following provisions:

a) Actual power cost rather than normalized power costs will be used.

b) All other elements of the earnings test will be determined in a manner consistent with the Commission's decisions in PGE's last general rate case, in a form generally provided in PGE's annual Results of Operations Report filed with the OPUC. Adjustments will be limited to Type 1 adjustments only.

7. Amortization of any SDCV Recovery Amount or SDCV Refund Amount will be determined by the Commission for each year. If approved by the Commission, amortization of the SDCV Recovery Amount may begin, subject to refund, prior to the Commission's final determination of SDCV Recovery Amount.

8. The deferral and amortization of power cost variances described in this Stipulation constitutes an automatic adjustment clause under the terms of ORS 757.210.

9. Interest will accrue on any SDCV Account balance at the interest rate authorized by the Commission for deferred accounts, which is currently PGE's authorized overall cost of capital. In addition, catch-up interest will apply to the SDCV Account balance by multiplying the balance by one-half and then multiplying by PGE's authorized interest rate.

10. Staff and PGE request implementation of a tariff consistent with the terms of this Stipulation beginning on the first day of the month following Commission approval. Staff and

PGE also agree to request and support deferral, beginning January 1, 2005, and amortization of power cost variances consistent with this Stipulation in Docket No. UM 1187. For the purpose of calculating the variance deferred between January 1, 2005, and the effective date of a tariff consistent with the terms of this Stipulation, the same method described above for calculating the SDCV Account balance and the SDCV Recovery Amount and SDCV Refund Amount shall apply.

11. The characteristics and terms of an ongoing power cost adjustment mechanism for calendar year 2007 and thereafter will be addressed in PGE's next general rate case. This Stipulation will not be used in whole or part as precedent in that proceeding. This Stipulation provides for a temporary mechanism only.

12. PGE agrees to obtain appropriate consultation services for the purpose of evaluating the statistical distribution of net power costs, at a cost of up to $100,000. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load, forced outages, and any correlations between these variables. Staff and PGE will work together to formulate a work statement to guide the work of the consultant. PGE will schedule quarterly public workshops to provide progress reports and receive input from interested parties. Staff and PGE reserve the ability to accept or reject the opinion or work product of the consultant for use in ratemaking, including in PGE's next general rate case. The consultant will report results by December 31, 2005, unless Staff and PGE agree to a different date. PGE will not seek recovery of the cost of these consultation services from customers.

13. Staff and PGE agree that this Stipulation is in the public interest and will produce rates that are fair, just and reasonable.

14. Staff and PGE shall file this Stipulation with the Commission. Staff and PGE agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation or the Stipulation in UM-1187, or adds any material condition to any final order which is not contemplated by this Stipulation, each party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other party within five (5) business days of service of the final order rejecting this Stipulation or the UM-1187 Stipulation, or adding such material condition.

15. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

16. The parties to any dispute concerning this Stipulation agree to confer and make a good-faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

17. Staff and PGE agree that this Stipulation represents a compromise in their positions. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. Staff and PGE agree that a Commission order adopting this stipulation will not be cited as precedent in other proceedings for the matters resolved in this stipulation.

18. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

ORDER NO. 05 1261

19. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

20. Appendix A to this Stipulation is a Term Sheet which provides further description of the terms of the Stipulation.

DATED THIS ___ day of April, 2005.

| | |
|---|---|
| PORTLAND GENERAL ELECTRIC COMPANY | STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON |
| ______________________________ | ______________________________ |

19. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

20. Appendix A to this Stipulation is a Term Sheet which provides further description of the terms of the Stipulation.

DATED THIS 11th day of April, 2005.

| | |
|---|---|
| PORTLAND GENERAL ELECTRIC COMPANY | STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON |
| ______________________ | ______________________ |

## UE-165/UM-1187 Settlement Term Sheet

- Base Power Costs are defined as the costs included in PGE's final RVM Monet run filed in mid-November, with updated cost of service loads to reflect customer elections in November.

- Updated Power Costs start with the Base Power Cost Monet run and update for the following factors:

  1. Actual hourly hydro generation.
  2. Actual electric prices using Dow Jones Mid Columbia Hourly Index prices to shape Dow Jones Mid Columbia Daily Index on and off-peak prices to hourly prices.
  3. Actual gas prices using daily index prices. Monet must be modified to accept daily gas prices.
  4. The procedure for updating Monet is more fully described in Attachment 1.

- The total variance is defined as the difference between the Updated Power Costs and Base Power Costs. The following sharing applies:

  1. A dead band of $15 million for higher power costs, $7.5 million for lower power costs
  2. All variances beyond $15 million (higher power costs) or $7.5 million (lower power costs) are shared 80 / 20 (Customers/PGE).

- An earnings test will be applied to determine a reasonable level of amortization. The following parameters apply to the earnings test:

  1. Recovery of any deferred amounts will be limited to those that result in PGE earning no greater than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that exceeds 10.5% on a regulated basis will be written off.
  2. Refund of any deferred amounts will be limited to those that result in PGE earning no less than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that is less than 10.5% on a regulated basis will be written off.
  3. For the purposes of the earnings test, actual power costs will be used rather than normalized power costs.
  4. All other elements of the earnings test will leverage from Commission decisions in PGE's last general rate case (UE-115) and which are generally provided in PGE's annual Results of Operations Report filed with the OPUC. Adjustments will be limited to Type 1 adjustments only.
  5. 

- Amortization of any deferred amounts, after application of the earnings test, will be decided later by the Commission. There will be two separate amortization dockets (one for any 2005 deferral, another for any 2006 deferral). At PGE's request, the parties agree to consider amortization of deferred amounts (subject to refund) prior to the Commission's final determination of deferral amounts.

- Parties agree to support this stipulation in the UE-165 docket for purposes of implementation beginning the calendar month after Commission approval of the stipulation. In addition, parties agree to support this stipulation in the UM-1187 docket for purposes of implementation beginning 1/1/2005.

- The characteristics of an on-going PCA for 2007 and beyond will be addressed in PGE's next general rate case. This agreement will not be used as a precedent in that proceeding.

- PGE agrees to provide $100,000 (not recoverable from customers) for the purpose of evaluating the statistical distribution of net power costs. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load, forced outages, and any correlations between these variables. The parties to the stipulation will work together to formulate a work statement to guide the work of the consultant. PGE will schedule quarterly public workshops to provide progress reports and receive input from interested parties. All parties are free to accept or reject the opinion or work products of the consultant for use in rate making, including PGE's next general rate case. Unless otherwise agreed to by the parties, the consultant will report results by 12/31/2005.

- Interest will accrue on any deferred amounts at the interest rate authorized by the Commission for deferred accounts, which is currently PGE's authorized overall cost of capital. In addition, catch-up interest will apply to the deferred amount by taking the deferral amount, multiplying by ½ (i.e., assuming the deferred amount accrues equally through the year) and multiplying by PGE's authorized interest rate.

g:\ratecase\opuc\dockets\ue-165_hydrotariff\settlement\term sheet.doc

**Attachment 1 of Term Sheet**
**Monet Update Methodology**

Updated Power Costs begin with the "Base Power Cost Monet run" and updates for actual hydro generation, electric prices and gas prices. The following outlines the specific procedures.

**Actual Hydro Generation**

Procedure
Take actual hydro hourly generation for each PGE hydro plant (PGE 66.67% shares of Pelton and Round Butte), Portland Hydro Project, and total Mid-C generation according to our Power Scheduling and Accounting System (PSAS). Because of the Mid-C hourly dispatch logic implemented in the 2005 RVM and continuing in the 2006 RVM, it will be necessary to override this logic to input the hourly Mid-C generation to Monet. One way to do this without modifying the Monet Visual Basic source code is to create a new PGE resource called "Mid-C Actual Generation", which would appear as a new line item in the Hydro Resource section of the Monet Energy report. Then, for each PGE hydro plant, the Portland Hydro Project and the Mid-C as a total, hourly generation will be placed into the hourly factor cells of the WSCCHydroCondition1 Sheet. The monthly factors will be adjusted to cancel with the product of the plant capacity and the annual factor. Then, there are three consequential contract effects of updating the hydro energy in Monet and the treatment of Daylight Savings Time.

1. Wells Settlement Agreement: This is a hydro-related contract whose energy and price is modeled as a function of the Wells plant generation. The modeling assumes that if there is more generation from Wells, PGE will receive more energy under the Wells Settlement Agreement. Further, the modeling bases the Wells Settlement Agreement pricing on the Wells plant energy. To capture both of these consequential effects of updating the hydro energy, we would need to obtain and model the monthly Wells plant generation on the PC_Input sheet and modify the Wells Settlement Agreement formulas on the PC_Input sheet accordingly.

2. Tribes Mid-C Index Purchase: This is an index-priced purchase from the Confederated Tribes of Warm Springs based on their share of Round Butte, Pelton and Regulating Project's generation after accounting for any fixed-priced sales of energy to PGE. Even though this is an index-priced purchase, it is indexed at the Mid-C, while in Monet the energy is incrementally valued at the PGE price, which is greater than the Mid-C price by 1.9% transmission losses, or roughly 1 $/MWh at a market price of 50 $/MWh. To capture this consequential effect of updating the hydro energy, we would update the monthly Round Butte and Pelton (and possibly the Regulating Project) plant generation on the PC_Input sheet, which would then flow through the modeling of the Tribes Mid-C Index Purchase.

3. Priest Rapids Renewal Contract Reasonable Portion Auction Payment: This is one component of the series of contracts that constitute the Priest Rapids Renewal. As modeled in the 2005 RVM, updating either the Priest Rapids hydro energy or the market electric price affects the Reasonable Portion Auction Payment.

4. Daylight Savings Time: Monet does not model Daylight Savings Time. We will adjust market electric prices and hydro generation as necessary to develop Updated Power Costs.

**Actual Gas Prices**

Procedure

Take daily index prices for Sumas, AECO and Malin from the Platts Database "GasDat" per Table 1. Enhance Monet to accept daily gas prices and input these to Monet. The other uses of the monthly gas prices in Monet excluding the fueling of Beaver and Coyote Springs, such as the gas transportation variable loss costs and Glendale Sales contract prices, would continue to use the monthly modeling on the PC_Input sheet. The monthly gas prices on the PC_Input Sheet would be calculated as the average of the daily index gas prices for that month. The gas financials (e.g. swaps) would be updated to the actual, settled values of the RVM swaps, which are settled based on monthly (not daily) gas index prices and the spot Canadian/US foreign currency exchange (F/X) rate at settlement. The RVM gas physical transactions, if any, would have their weighted average costs of gas (WACOGs) updated based on the actual, settled values of those transactions, which are again based on monthly index prices and the spot F/X rate at settlement. We will update the value of any RVM Canadian Dollar hedges to reflect the actual settled value of such hedges.

**Table 1**
**Gas Price Index**

| Monet | Platts GasDat |
|---|---|
| Sumas | Gas Daily "Sumas", $US |
| AECO | Gas Daily "Nova(Aeco-C,NIT)", $US |
| Malin | Gas Daily "Malin", $US |

**Actual Electric Prices**

Procedure

Take daily on/off-peak and hourly index prices for the Mid-C from Dow Jones. Apply the hourly index shape to the daily on/off-peak index to obtain an hourly electric price whose price level is based on the daily index but whose hourly shape is based on the hourly index. This is done to preserve the hourly volatility present in the hourly index prices while maintaining the simultaneous day-ahead views of the electric and gas market prices. Any gaps in the hourly data would be filled in based on shapes from similar periods where data are available. At some point in the process before inputting the prices to Monet, multiply the Mid-C prices by the factor 1.019 to convert them to PGE prices, consistent with the RVM model.

**Dispatchable Contracts**

Procedure

PGE will also appropriately model any dispatchable contracts based on the terms (e.g., capacity, heat rate, natural gas price index, exercise fee, etc.) and constraints (e.g., minimum take in hours, maximum take for delivery period, etc.) of the contracts, using the actual gas and electric prices used in the Updated Monet run. Current dispatchable contracts include:

- Superpeak Capacity Agreement
- ColdSnap Capacity Agreement
- On-Peak Tolling Agreement

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1187

| | |
|---|---|
| In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Costs and Benefits Due to Hydro Generation Variation | **STIPULATION** |

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE") and Staff of the Public Utility Commission of Oregon ("Staff").

On December 30, 2004, PGE filed its Application in this docket seeking deferral for later ratemaking treatment of the costs and benefits due to variation in PGE's owned and contract hydro generation resources. PGE sought deferral of those costs and benefits beginning January 1, 2005. The Application stated that PGE would determine the variance consistent with the method contained in its proposed Hydro Generation Adjustment tariff in Docket UE 165. An amended application was filed on January 21, 2005, to clarify that this deferral application was filed because of the existing drought conditions in the Pacific Northwest and that, therefore, PGE was requesting that the Public Utility Commission of Oregon ("Commission") approve this Application irrespective of the ultimate outcome in UE 165.

The Hydro Generation Adjustment tariff proposed in Docket UE 165 was an ongoing mechanism designed to capture the costs and benefits of the variation in hydro generation. After two rounds of testimony in UE 165, numerous data requests and responses, and settlement conferences over many months, Staff and PGE have agreed upon terms of a temporary cost variance mechanism to be applied to calendar years 2005 and 2006. As a result, Staff and PGE have entered into a Stipulation in docket UE 165, and this Stipulation, setting forth the terms of that agree-upon temporary mechanism, and seeking Commission orders implementing that temporary mechanism.[1] Specifically, Staff and PGE agree to and request that the Commission adopt orders in this docket implementing the following:

STIPULATION

1. Attached as Exhibit "A" is a copy of the Stipulation between PGE and Staff in UE 165. The UE 165 Stipulation is incorporated herein. Staff and PGE request an order in this docket allowing the deferral and amortization of power cost variances under the terms set forth in paragraphs 1 through 7 of the UE 165 Stipulation. Staff and PGE's intent and request is that the terms set forth in the UE 165 Stipulation govern the calculation and amortization of cost variances for all of calendar years 2005 and 2006. In this docket, Staff and PGE request a Commission order allowing such calculation and amortization from and after January 1, 2005, to the effective date of the implementation of the requested temporary cost variance tariff in UE 165. Staff and PGE agree that the deferral and amortization of power cost variances as set forth in paragraphs 1 through 8 of the UE 165 Stipulation is an automatic adjustment clause under ORS 757.210. The Parties agree to support the deferral and amortization of power cost variances as described in the UE 165 Stipulation and neither Party will propose or support an earnings test applicable to the System Dispatch Cost Variance Account (SDCV Account) different from the earnings test set forth in paragraphs 4 through 6 of the UE 165 Stipulation.

2. The characteristics and terms of an ongoing power cost adjustment mechanism for calendar year 2007 and thereafter will be addressed in PGE's next general rate case. This Stipulation will not be used in whole or part as precedent in that proceeding. This Stipulation provides for a temporary mechanism only.

1 It is anticipated that the terms and conditions of an ongoing PCA beginning in 2007 will be addressed in PGE's next general rate case.

3. Staff and PGE agree that this Stipulation is in the public interest and will produce rates that are fair, just and reasonable.

4. Staff and PGE shall file this Stipulation with the Commission. Staff and PGE agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation or the Stipulation in UE 165, or adds any material condition to any final order which is not contemplated by this Stipulation, each party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other party within five (5) business days of service of the final order rejecting this Stipulation or the UE 165 Stipulation, or adding such material condition.

5. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

6. The parties to any dispute concerning this Stipulation agree to confer and make a good-faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

7. Staff and PGE agree that this Stipulation represents a compromise in their positions. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. Staff and PGE agree that a Commission order adopting this stipulation will not be cited as precedent in other proceedings for the matters resolved in this stipulation.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

ORDER NO. 05 1261

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

DATED THIS ___ day of March, 2005.

PORTLAND GENERAL ELECTRIC COMPANY

______________________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

______________________________

9. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

DATED THIS 11th day of April, 2005.

| | |
|---|---|
| PORTLAND GENERAL ELECTRIC COMPANY | STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON |
| ______________________ | ______________________ |

ORDER NO. 051261

ATTACHMENT OMITTED