ORDER NO. 01-420

ENTERED MAY 11 2001

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 995/UE 121/UC 578

In the Matter of the Application of PACIFICORP for an Accounting Order Regarding Excess Net Power Costs. (UM 995)	)	
In the Matter of PACIFICORP's Application for Partial Authorization of Its Request to Defer Excess Net Power Costs and Approval of Its Request to Implement an Amortization in Rates of Deferred Excess Net Power Costs. (UE 121)	)	ORDER
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES and CITIZENS' UTILITY BOARD,	)	
Complainants,	)	
vs.	)	
PACIFICORP,	)	
Defendant. (UC 578)	)	

DISPOSITION: DEFERRAL APPROVED; STAFF MECHANISM APPROVED

On November 2, 2000, PacifiCorp applied for an accounting order authorizing deferral of excess net power costs, to begin on that date for later amortization in rates. The application was filed pursuant to ORS 757.259(2), which allows the Commission on application of a utility to authorize deferral of certain items for later incorporation in rates. On December 4, 2000, the Industrial Customers of Northwest Utilities (ICNU) and Citizens' Utility Board (CUB) filed comments opposing the application. Commission Staff filed comments raising a number of issues for discussion and indicating that "Staff may be willing to support PacifiCorp's application." PacifiCorp filed reply comments on December 14, 2000.

On January 9, 2001, the Commission issued Order No. 01-085, which found that PacifiCorp's application could proceed as a matter of law. The Commission made the following findings:

- That PacifiCorp had "convincingly rebutted CUB's and ICNU's legal arguments against its application" (at 11);
- That the application "does not violate the deferred accounting statute" inasmuch as "this filing may minimize the frequency of rate changes" (*id.*);
- That "the application and the circumstances underlying it are also within the ambit of prior Commission decisions on deferred accounting" *(id.*); and
- That "the expenses for which [PacifiCorp] seeks deferred accounting are based on extraordinary behavior of the power markets and are not ordinary power cost expenses" *(id.*).

At a settlement conference on February 13, 2001, the parties agreed on the following list of issues to be addressed in briefs:

1. What components should be included in the deferred account?
2. What is the appropriate baseline?
3. Should the mechanism have a deadband?
    a. What size?
    b. Should it be symmetrical?
4. Should there be sharing?
    a. How much?
    b. Should the sharing be symmetrical?
5. Should there be a cap?
6. If there is a sharing mechanism, should the Oregon allocation factor be based on actual PacifiCorp states' loads?
7. Are there alternative mechanisms that should be considered?
8. Is it appropriate to apply the same mechanism retroactively that you apply prospectively?
9. How long should this mechanism remain in place?
10. Is it appropriate to apply different mechanisms to different utilities in recognition of different circumstances faced by those utilities?
11. Are there any other issues the Commission should consider?

On January 18, 2001, PacifiCorp submitted a tariff filing in UE 121 for approval of a $22.8 million deferral and to begin amortization of that amount in rates. The tariff filing was in accordance with a stipulation between Staff and PacifiCorp, "Stipulation re Amortization of Deferred Power Costs in Rates," included in Order No. 01-171 as Attachment B of Appendix A, under which Staff agreed with PacifiCorp that "the Company has incurred, at a minimum, $22.8 million of excess net power costs for which deferral and amortization in rates is appropriate." (Stipulation at 1.) Staff agreed to support the UE 121 tariff filing but "reserve[d] its position with respect to the deferral and amortization of the remaining excess net power costs for which the Company is seeking deferral authority."
(*Id.* at 2.)

In response to the UE 121 tariff filing, CUB and ICNU filed a formal complaint on January 22, 2001, which was docketed as UC 578. The complaint challenges the prudence of PacifiCorp's expenditures and asks to make any increase in UE 121 subject to refund. In its Order No. 01-171, entered February 13, 2001, the Commission authorized the deferral of $22.8 million. On February 21, 2001, the Commission authorized the amortization in rates of $22.8 million, thereby increasing PacifiCorp's rates by 3 percent (Order No. 01-186). According to the Order, "the $22.8 million being amortized is subject to refund pursuant to ORS 757.215(4)."

On April 5, 2001, the parties addressed the Commission in a Special Public Meeting, setting out their arguments and answering questions from the Commissioners.

This order deals with the remainder of PacifiCorp's excess net power costs, for which it also seeks deferral. Although parties convened in several settlement conferences, they were unable to reach agreement on the issues or even on the reliability of the data provided by the company.

Staff's Proposal. Staff argues that its sole issue in this docket is an answer to the question: for what changes in PacifiCorp's power costs should Oregon customers be responsible between rate cases? Utilities typically bear the risk for cost changes in normal operating expenses between rate cases. However, Staff accepts that PacifiCorp is being buffeted by high purchased power costs, its Hunter plant outage, and unusually poor hydro conditions. Staff believes that Oregon customers should pay their fair share of costs associated with these extraordinary events and generally supports PacifiCorp's application to defer power costs.

However, Staff maintains that many factors other than increases in power costs enter into a determination of Oregon customers' fair share of PacifiCorp's escalated power costs. Further, these same factors should also be considered in determining the appropriate mechanism to achieve a fairly apportioned sharing of costs between PacifiCorp and its Oregon customers.

Staff lists the principles that have guided it during settlement discussions and in crafting alternative mechanisms that allow for an appropriate level of sharing between the company and its customers:

- Utilities typically bear the risks and rewards of revenue and cost changes between rate cases and should be protected only to the extent that cost changes are truly extraordinary.
- Risks should not be completely shifted from PacifiCorp to its customers. It is appropriate to share even the risks of extraordinary cost changes.
- PacifiCorp should receive incentives to minimize costs.
- Between rate cases, Oregon customers should be shielded, to the extent possible, from the effects of load growth in PacifiCorp's other jurisdictions.

Costs normally borne by the company. Utilities typically bear the risk for changes in normal operating expenses between rate cases. However, Staff believes that the magnitude of PacifiCorp's potential power cost changes since UE 111, its last general rate case, is the result of a highly unusual wholesale market, an unplanned extended plant outage, and poor hydro conditions. Staff believes that these extraordinary circumstances justify not only deferral of a portion of the variance in power costs over a base level but also a sharing between customers and the company.

Staff maintains that the utility normally bears costs associated with weather risk. Loads, costs, and revenues are normalized for weather during rate cases. Accordingly, a power cost recovery mechanism that shifts all risk to customers is inappropriate. Thus, Staff argues that the Commission should choose a deferral or recovery mechanism for operating expenses that balances risk between the company and its customers.

Further, the fact that PacifiCorp is a multi jurisdictional company creates a unique situation regarding the company's request for any recovery of increased costs. Generally, Oregon is allocated approximately 33 percent of the company's system power costs. Typically, load growth in the other jurisdictions and the resulting changes in allocation factors have a ratemaking effect in Oregon only during a general rate case. Staff believes that between rate cases, Oregon customers should not bear the effects of load growth in PacifiCorp's other jurisdictions, the other 67 percent of the system. This is particularly true in light of remarkable growth in Utah. This growth has increased PacifiCorp's exposure to high market prices and overall power costs the company is asking Oregon customers to pick up.

Staff contends that Oregon customers should bear their share of replacement power costs for the Hunter outage, poor hydro conditions, and power costs associated with Oregon load. Ideally, Oregon customers' responsibilities would end there. The difficulty, however, is how to isolate Oregon customers from load growth effects in other jurisdictions, since the company generation operates as an integrated system. Staff is particularly concerned that disproportionate load growth in other states could exacerbate the company's increases in power costs.

Deferral Mechanisms. Staff suggests two alternate deferral mechanisms in order to allow PacifiCorp recovery of a reasonable portion of its abnormal power cost increases and yet to partially shield Oregon customers from increased power costs caused by PacifiCorp load growth in other jurisdictions. Both options are a variation of a deferral mechanism agreed to by PGE in UM 1008/1009.

In those dockets, Staff, PGE, and interested parties reached a stipulated agreement on a mechanism for recovery of changes in net variable power costs (NVPC). Staff believes that this mechanism should be used, with some modifications, for PacifiCorp. The PGE mechanism is structured in the following manner:

1. A baseline NVPC;
2. A deadband for power cost changes equivalent to +/- 250 basis points return on equity around the baseline (no sharing);
3. A 50/50 sharing for power cost changes equivalent to between 250 and 400 basis points (basis point threshold established before effect of sharing is calculated); and
4. For power cost changes equivalent to more than 400 basis points, the sharing becomes 90/10 (customers bear 90 percent, the company bears 10 percent).

Staff believes that this mechanism, with modifications, will provide PacifiCorp reasonable earnings protection between rate cases. The bands are structured to recognize the costs a company would ordinarily absorb before making a rate filing. The mechanism also recognizes that the extraordinary nature of current power costs requires a sharing of the risk between the company and its customers. Finally, this mechanism provides the company with an ongoing incentive to minimize its power costs, one of the three principles Staff articulated above.

To address Staff's concerns regarding the effect of load growth in other jurisdictions, Staff proposes either of two modifications to the PGE mechanism.

Option 1: Revise the sharing percentage over 400 basis points from 90/10 to 75/25 for customers/company; or

Option 2: Increase the baseline NVPC by the revenue margin (retail revenue less power costs) PacifiCorp is receiving from non Oregon load growth since the base year (1998).

Staff prefers Option 1. It is more straightforward and will provide the appropriate signals to Oregon customers about the current cost of power and the rewards that can be achieved through energy efficiency. The PGE mechanism, coupled with the modifications suggested in Option 1, also provides an appropriate sharing of risk between the company and its ratepayers.

Staff's Discussion of the Issue List:

1. What components should be included in the deferred account? Staff believes that the deferred account should contain the actual power cost differences resulting from Staff's proposed mechanism. As with PGE, the final amount of deferrals subject to amortization must be calculated over the entire deferral period; therefore, monthly entries will be subject to true up.

2. What is the appropriate baseline? Staff proposes to use the NVPC filed by the company in its last general rate case (UE 111) adjusted to include the California load and to include the revenue generated by Wah Chang's contract. During UE 111, the parties agreed to exclude California from the company's NVPC, because it was assumed that the company's system in that state would be sold. The sale has not occurred and it is uncertain that it will take place. Further, Staff advocates shaping the monthly UE 111 loads using 1999 actual power costs. The Wah Chang contract specifies that the customer pay PacifiCorp market based rates. The baseline should be raised by the amount paid by Wah Chang under the contract (excluding the inflation adjusted adder for transmission and distribution services). The unadjusted baseline would allow PacifiCorp to recover costs to serve Wah Chang from other customers while it retains all the higher revenue generated by the contract. Staff's proposal would correct that mismatch.

Using the UE 111 baseline as a starting point also prevents the company from recovering what it gave up on power costs in exchange for concessions by other parties on other costs in the UE 111 settlement agreement. Furthermore, the final stipulation was negotiated as a bottom line revenue requirement change, and there was no agreement on the level of power costs. Staff's proposed baseline alleviates the need to speculate what power cost level was implicit in the final UE 111 revenue requirement.

3. Should there be a deadband? What size? Should it be symmetrical? Staff believes the mechanism should have a deadband to capture normal business variability to which the company is generally exposed between rate cases. Such normal variability would not trigger a rate filing by the company or a show cause request by other parties. As was adopted for PGE, Staff proposes that the width of the band be symmetrical and equivalent to +/- 250 basis points return on equity.

4. Should there be sharing? What amount? Should it be symmetrical? Staff advocates sharing the variability beyond the deadband between the company and customers.

Between 250 and 400 basis points above the baseline, Staff urges a sharing of 50/50. Over 400 basis points, the sharing would be 75/25.

Staff believes that this proposal for risk sharing appropriately apportions to the company risks a company would normally assume between rate cases, including weather risk and other risks that a company always assumes. The 75/25 sharing in the outer band will help shield Oregon customers from assuming costs associated with load growth in other jurisdictions. Finally, the proposed sharing levels provide PacifiCorp with incentives to minimize its power costs.

Staff notes that PacifiCorp has argued that it should not be subject to the same type of sharing mechanism as PGE because unlike PGE it already knows that its power cost changes will be a significant increase. Staff disagrees with this logic. Whether extraordinary power cost increases are potential or actual, between rate cases it is appropriate that they be shared between the customers and stockholders.

5. Should there be a cap? Staff answers this in the negative.

6. If there is a sharing mechanism, should the Oregon allocation factor be based on actual PacifiCorp states' loads? Staff answers no. Jurisdictional allocation factors, Staff contends, should be calculated on normalized loads, as usual. To mitigate load changes in other states, Staff proposes that customers share 75 percent of cost changes outside the second band above the baseline. If the Commission adopts a sharing percentage of 75 percent (or less) outside the second band, Staff argues that the UE 111 allocation factors for 1998 should be used. Otherwise, there would be double counting for that effect. Alternatively, if the Commission adopts a sharing percentage greater than 75 percent, Staff believes that normalized loads should be used for the particular calendar year (the year 2000 for November and December deferrals and the year 2001 subsequently). Regardless of which annual period(s) are used for calculating the factors, California should be included because it is still part of PacifiCorp's system.

7. Are there alternative mechanisms that should be considered? Other approaches were discussed during settlement, but Staff believes its mechanism is fair to PacifiCorp and its customers. Staff's mechanism offers all parties protection and risk sharing. It also gives the company incentives to minimize its power costs.

8. Is it appropriate to apply the same mechanism retroactively that you apply prospectively? According to Staff, if the mechanism is well designed, there should be no problem applying it both retroactively and prospectively. Staff believes its mechanism fits this criterion. Costs already incurred are not necessarily 100 percent recoverable. The inclusion of costs in rates has always been subject to Commission decision making. Staff notes that the costs that parties are trying

to address in this docket have traditionally been the responsibility of utilities between rate cases. Staff sees no logic in treating retroactive or prospective costs differently.

9. How long should the mechanism be in place? Staff maintains that any mechanism the Commission implements should be in place until rates in UE 116 are in effect, although the baseline for deferrals could require modification if a power cost adjustment is adopted before UE 116 rates go into effect.

10. Is it appropriate to apply different mechanisms to different utilities in recognition of the different circumstances they face? Yes, Staff contends. The mechanism Staff proposes to implement in this docket has a larger sharing in the outer band than the mechanism stipulated to by Staff, PGE, and other parties for PGE. The percentage of sharing that Staff proposes for PacifiCorp is prompted by the fact that PacifiCorp is a multi jurisdictional utility. Staff believes that PacifiCorp's Oregon customers require some protection against costs associated only or primarily with providing energy in other jurisdictions.

11. Are there other issues the Commission should consider? Staff believes that all deferred power costs should be subject to a prudence review. October 1 has been set as the deadline for such a review. Staff requests that the Commission reiterate that allowing a deferral is not the same as allowing amortization of the deferral. A prudence review must occur prior to the Commission's decision to allow amortization of previously deferred funds.

PacifiCorp's Position. PacifiCorp argues that since May 2000, utilities have faced extraordinary increases in the prices for electricity in the wholesale market. When PacifiCorp filed its application in November 2000, the company expected the annual average market price of power during 2001 to be approximately three times higher than the $23 per MWh annual average market price of purchased power included in the UE 111 stipulation (application at 2). Now the figure is ten times that, or more. PacifiCorp's strategy, in keeping with its integrated resource plan (IRP), has been to rely on the market for short term purchases to fill in during the peaks of a generally balanced load/resource situation. This strategy has become costly. The market purchases used to fill in the occasional short term deficiency in supply are no longer priced at 20 to 30 mills but on average between 200 and 300 mills and as high as 5000 mills.

PacifiCorp argues that the operational risks normally borne by utilities—the effects of occasional plant outages or variations in weather—have become greater risks than have ever been taken into account in determining an allowed rate of return. Starting after it filed this application in November, PacifiCorp has lost approximately six months' generation by one of its largest generating units, the Hunter coal fired generating unit No. 1, which produces about 430 MW of electricity. Replacement power costs are ten times normal.

The Hunter loss is compounded by the impact of hydro conditions, with streamflows at about 59 percent of average. PacifiCorp must replace generation lost from its considerable hydro portfolio, about 1200 MW of installed capacity, through market purchases. The impact of such hydro conditions on other utilities throughout the region further increases the cost of such purchases. The additional load due to colder than normal winter weather or warmer than normal summer weather will also have to be satisfied with market purchases at extraordinary prices.

PacifiCorp argues that any of these events could cause a well managed utility to fall short of a reasonable level of earnings. A confluence of such events could cause serious financial consequences. PacifiCorp contends that it finds itself at such a confluence of events. Its stock price has declined over 16 percent since mid November, just prior to the Hunter outage. On January 22, 2001, Moody's changed PacifiCorp's outlook from neutral to negative, and on February 13, 2001, Standard and Poor's placed the company on credit watch with negative implications. The potential downgrade in the credit rating of PacifiCorp's securities below "A" would increase PacifiCorp's borrowing costs substantially, and such costs would be borne by customers in subsequent rate proceedings. PacifiCorp argues that further deterioration in its credit rating could preclude its access to capital markets, with disastrous consequences for its ability to provide safe and adequate utility service.

PacifiCorp opposes Staff's proposed approaches to recovery. A sharing approach to provide incentive to the company to control costs would deny PacifiCorp the ability to recover more than half the excess net power costs it has incurred since November 2000. As indicated in Staff's memo dated February 14, 2001, in UE 121, Staff's proposed mechanism here would enable PacifiCorp to defer only \$56.7 million of the \$114.3 million of excess net power costs incurred since November 2000. If the impact of the Hunter outage is excluded, PacifiCorp argues that the result is even worse. PacifiCorp would be allowed to defer only about 34 percent of its excess net power costs, or \$27.9 million of the \$82.2 million incurred. PacifiCorp also notes that the remaining 34 to 49 percent that can be deferred is subject to a prudence review.

PacifiCorp's Proposal. PacifiCorp proposes that it receive an opportunity to recover most of its excess power costs, less an appropriate sharing percentage to provide an incentive to control costs, in keeping with Commission precedent. For the period up to and including March 31, 2001, PacifiCorp proposes that it be authorized to defer 80 percent of its excess net power costs for later recovery in rates.

For the time after March 31, the company proposes a three-tier approach: a deadband of 150 basis points around the baseline, spread on a monthly basis, with no deviations eligible for deferral. Within the next band of 100 basis points (between 150 and 250 basis points around the baseline) a sharing allocation of 67/33 percent, with the company deferring 67 percent of its excess net power costs above the 150 basis points and, on the lower end, sharing with customers in the same percentages. For amounts in excess of 250 basis points around the baseline, the sharing allocation would be 95/5 percent.

Amounts deferred in accordance with this mechanism would be subject to a prudence review prior to their recovery in rates. Deferrals would cease on the rate change in UE 116, as stated in PacifiCorp's application. If the baseline is reset through a filing for an interim rate change or the implementation of a power cost adjustment, deferrals would continue, although presumably at a reduced level due to the higher baseline.

PacifiCorp lists four bases for its proposal:

1. PacifiCorp seeks deferral for its actual, prudently incurred excess net power costs. Power costs are a major expense item over which PacifiCorp has little control.
2. The extraordinary events in the wholesale power markets increase out of the normal range the normal operating risks borne by the company—routine plant outages, weather impacts, bad hydro conditions.
3. Although limited sharing is appropriate as an incentive for cost control, PacifiCorp should be able to recover most of its actual, prudently incurred excess net power costs.
4. The proposal conforms to Commission precedent for treatment of replacement power costs and sharing percentages for pass-through of energy costs.

PacifiCorp's Discussion of the Bases:

1. PacifiCorp maintains that it seeks deferral for its actual, prudently incurred power costs. PacifiCorp's IRP called for the company to rely on the market for purchases to fill in the peaks of an otherwise generally balanced load/resource situation. To the extent PacifiCorp could be expected to plan for conditions, it argues that it has done so through its IRP. Matching loads and resources over a range of expected conditions are circumstances over which PacifiCorp has some control and for which it may be held accountable in a subsequent prudence review.

The events of the last several months—poor hydro, cold weather, and the extraordinary behavior of the energy markets—are, however, outside the company's control. And PacifiCorp has limited, if any, control over the type of catastrophe that caused the extended outage at the Hunter unit. There has been no allegation of imprudence about that outage, nor is there evidence of mismanagement or improper maintenance. If the prudence review shows imprudence, that could limit PacifiCorp's ability to recover costs resulting from the outage. For this analysis, PacifiCorp asks the Commission to presume the outage to be an event over which PacifiCorp has little control.

PacifiCorp argues that the Commission has previously recognized that utilities have little control over some costs and should not be denied recovery of such costs on the basis of incentives for cost control.[1]

2. The normal operating risks borne by PacifiCorp (plant outages, weather impacts, bad hydro conditions) have unacceptable effects due to extraordinary circumstances in wholesale power markets. Power that formerly cost 20 to 30 mills to replace lost generation now costs 200 to 300 mills or more. The result is, according to PacifiCorp, a cost impact that is not normal and is unacceptable for a utility to bear. According to PacifiCorp, the Commission has previously determined that the costs at issue in this proceeding are based on extraordinary behavior of power markets and are not ordinary power cost expenses. Order No. 01-085 at 11.

PacifiCorp's response to CUB data request 9a illustrates the impact of "normal" operating risks when combined with the extraordinary conditions in today's wholesale energy markets. The impact of poor hydro conditions at last year's wholesale market prices, which were relatively normal, would have been about $15 million for the period from November 2000 through September 2001. At current market prices, the impact is expected to be substantially greater. Similarly, the impact of the outage at Hunter Unit No. 1, if priced at last year's wholesale market prices, would have been less than $10 million. At current market prices the impact is expected to be about $65 million.

3. An incentive to control costs is appropriate, but it is inappropriate to deny recovery of most actual prudently incurred power costs. A recovery of less than 100 percent of a utility's prudently incurred power costs is claimed to be necessary to provide an incentive for a utility to control costs. While that concept may be acceptable, it cannot be used as Staff proposes to preclude recovery of the vast majority of the utility's prudently incurred power costs.[2]

4. PacifiCorp's proposal, which would result in 80 percent recovery of amounts deferred prior to March 31, is in accordance with previous Commission precedent. For

[1] PacifiCorp here cites to Order No. 89-1046, UG 73. That case deals with purchased gas adjustments, which are similar to power cost adjustments (PCAs). As we decide below, this docket is not the forum to discuss PCAs.

[2] At this point in its brief, PacifiCorp enters into a discussion of a proposal Staff made at one of the settlement conferences. The proposal was not identical to Staff's final proposal presented above. Counsel for Staff moved to strike the portion of PacifiCorp's brief that dealt with Staff's settlement conference proposal. That motion was granted.

instance, PGE for several years had in place a PCA that allowed 80 percent recovery of changes in power costs. Under the 80/20 PCA tariff filed by PGE, rates would vary depending on hydro availability, fuel costs, thermal plant efficiency, and cost of purchased power. UF 3518, Order No. 79-830. In adopting the PCA, the Commission noted that the mechanism included "[o]nly costs beyond the company's control." Order at 5. As to the 80/20 sharing, the Commission stated: "Since only a portion of the eligible costs are allowed recovery, the company is given an incentive to obtain its needed power at the lowest possible cost." *Id*. There was no deadband precluding recovery of any costs, nor was there a range where 50 percent of the utility's actual power costs were disregarded.

The Commission also allowed 90 percent recovery, later reduced to 80 percent, of replacement power costs arising from a plant outage. In December 1991, the Commission authorized PGE to defer 90 percent of Trojan outage excess power costs, beginning in November 1991 and ending on Trojan's return to service. UM 445, Order No. 91-1781. Subsequently, the Commission authorized deferral of 80 percent of the utility's incremental power replacement costs from a Trojan nuclear plant outage. UM 529, Order No. 93-309.

It should be noted that a sharing rather than full recovery was adopted in UM 529 due to the unusual circumstances. The 20 percent underrecovery imposed on the utility was designed to reflect the operational risk that PGE would normally have assumed with respect to Trojan and PGE's ability to reduce other Trojan related costs. PacifiCorp has no corresponding ability to offset higher power costs through plant specific savings. In the absence of this ability, arguably the 90 percent recovery factor approved in UM 445 is the general rule for the recovery of replacement power costs.

In other cases, recovery of purchased power costs under the deferred accounting statute was not subject to a sharing mechanism. In Idaho Power Company, UM 480, Order No. 92-1130, the Commission authorized Idaho Power to defer part of Oregon's share of excess power supply costs commencing March 23, 1992, the date of Idaho Power's application, through December 31, 1992. The percentage of recovery was tied to the level allowed in a temporary rate increase by the Idaho Public Utility Commission. The authority for the Commission's action was ORS 757.259, the deferred accounting statute.

Similarly, in Idaho Power Company, UM 673, Order No. 94-1111, the Commission authorized deferred accounting treatment for 60 percent of Oregon's share of the deferred power costs for a period beginning May 13, 1994, the date of the application, through December 31, 1994. The basis for the Commission's action was the deferred accounting statute, ORS 757.259. According to the Commission's decision, the deferral was appropriate for a portion of the utility's drought related excess power supply costs. UE 91, Order No. 95-690 (allowing recovery of amounts deferred under Order No. 94-1111). Thus, the 60 percent recovery was not based on a sharing approach but on the percentage of generation produced by hydro resources.

PacifiCorp's Discussion of the Issues List:

1. What components should be included in the deferred account? PacifiCorp contends that the account should contain "excess net power costs." These are to be calculated as the product of: (a) the difference between the net power costs implicit in the stipulation approved by the Commission in UE 111, on a per MWh basis, and the company's actual net power costs during the deferral period, on a per MWh basis; and (b) the retail load used for setting rates in UE 111. The excess net power costs will be calculated on a monthly basis. This method will allow PacifiCorp to defer the extraordinary net power cost increases it is incurring to serve the customer load that is reflected in rates.

2. What is the appropriate baseline? The starting point to determine this is the level of net power costs incorporated in the stipulation approved by the Commission in UE 111. If the power cost items in the stipulation are simply added, the resulting figure is $415,718,353. Given that the stipulation was not specific about the level of power costs included, PacifiCorp proposes using $437,457,229 as the baseline. The baseline was calculated by spreading pro rata the difference between PacifiCorp's proposed revenue requirement and the increase agreed upon in the stipulation. Adjusting this figure to reflect the difference between the retail load used for setting rates in UE 111 (5,739 aMW) and the retail load assumed in UE 116 (6,067 aMW) increases the baseline to $462,392,626. This is the proposed baseline for purposes of calculating deferral amounts. It represents the amount of net power costs currently reflected in rates, as adjusted to reflect changes in load.[3]

3. Should the mechanism have a deadband? What size? Should it be symmetrical? PacifiCorp argues that for prospective periods the mechanism should have a deadband. A utility should be expected to bear the power cost variations associated with normal operating risks at typical market prices for power purchases. A deadband of 150 basis points, as proposed by PacifiCorp, is sized to achieve this objective.[4]

The deadband should be symmetrical. The utility should have an equal chance to achieve rewards and to incur risks. PacifiCorp believes that setting a proper baseline is critical in creating this equal chance. For prior periods, there should be no deadband. The actual outcome is known and the deadband serves only to disallow the utility's actual prudently incurred costs.

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[3] In keeping with the ruling striking portions of PacifiCorp's brief that relate to Staff's settlement conference proposal, we have disregarded a portion of PacifiCorp's argument about Staff's proposed baseline calculation that is not reflected in Staff's briefed proposal to the Commission.

[4] A discussion of Staff's settlement proposal on this issue has been omitted. See Footnote 2 above.

4. Should there be sharing? How much? Should it be symmetrical? PacifiCorp contends that for prior periods there should be sharing at the rate of 80/20. For prospective periods there should be a sharing outside the 150 point deadband as follows:

Within the next band of 100 basis points, between 150 and 250 basis points around the baseline, there should be a sharing of 67/33, with PacifiCorp deferring 67 percent of its excess net power costs above the 150 basis points and, on the lower end, a sharing with customers at the same percentage. For amounts in excess of 250 basis points around the base line, the sharing allocation would be 95/5 percent.

The deadband and the relative sharing percentages acknowledge the extent to which the company may be able to avoid incurring the costs. The 95/5 split recognizes that extraordinary circumstances are occurring and that PacifiCorp is unlikely to be able to take actions to avoid the impact of such circumstances. PacifiCorp should be able to recover almost all such costs.

5. Should there be a cap? PacifiCorp answers no, just as there is no limit to the utility's exposure to higher power costs. Situations involving extremely high power costs are those the utility is least likely to be able to control. At these extremely high levels, a recovery closer to 100 percent is warranted. A cap would terminate recovery.

6. If there is a sharing mechanism, should the Oregon allocation factor be based on actual PacifiCorp states' loads? PacifiCorp answers no. Allocation factors are typically set only in general rate proceedings and are not reexamined between rate cases. PacifiCorp would willingly reexamine allocation factors in the context of a settlement discussion, but that would be unusual.

7. Are there alternative mechanisms to consider? PacifiCorp believes that the Commission should consider a PCA similar to that in place for the gas distribution companies. Electric utilities should be able to set rates periodically (e.g., quarterly) to recover excess net power costs based on projections, with monthly deviations between actual and forecasted costs subject to a sharing mechanism. The 3 percent limitation under the deferred accounting statute precludes large deferrals, so a quarterly resetting of the base rates should be considered.

8. Is it appropriate to apply the same mechanism retroactively that is applied prospectively? PacifiCorp believes not, for the reasons set out above.

9. How long should this mechanism remain in place? Deferrals would cease on the rate change in UE 116, as stated in PacifiCorp's application. If the baseline is reset earlier through a filing for an interim rate change of the implementation of a PCA mechanism along the lines of that

discussed in Item 7 above, deferrals would continue, although presumably at a reduced level due to the higher baseline.

10. Is it appropriate to apply different mechanisms to different utilities in recognition of different circumstances faced by those utilities? Yes, according to PacifiCorp. Utilities have different strategies for load/resource balance and dependence on wholesale power markets. The mechanisms need to register the utility's exposure to variations in net power costs, dependency on hydro, and load growth characteristics. Moreover, utilities are likely at different starting points with respect to their ability to succeed under a sharing mechanism. In PacifiCorp's case, the outage at Hunter since late November guarantees that PacifiCorp will be underrecovering and will not have an equal chance to achieve rewards and to bear the risk of loss. PGE appears to be in a position where a reasonably set baseline would give an equal opportunity for gains versus losses.

CUB's Position. CUB believes that the Commission has insufficient information on the record to issue a legally binding order in this matter. The information available does not permit the Commission to determine PacifiCorp's actual financial position, what kind of exposure ratepayers have to higher prices due to the deferred account, or why PacifiCorp found itself going short into the winter, if indeed it did. CUB notes that PacifiCorp's responses to data requests were sometimes inconsistent and that it is still uncertain about the answers to some of its questions.

CUB contends that the deferred account should not be allowed to grow with the expectation that at some later date we can consider the real issues behind the deferral. As the Commission's approval and amortization of the 3 percent rate increase shows, once a deferred account begins to grow, there is pressure to allow recovery. Second, imprudence is not the only reason costs might not be appropriate for deferred accounting treatment. For instance, the Commission might find that individual wholesale sales for resale contracts were prudent when they were signed, but since PacifiCorp received the profits from these contracts between rate cases in the early years of the contracts, PacifiCorp bears the responsibility for the losses between rate cases. Third, if PacifiCorp is unwilling to provide a coherent factual basis to support its deferred account filing, why should we believe that PacifiCorp will provide a coherent factual basis to support a prudence filing? Fourth, the company has not been forthcoming regarding the potential size of the deferred account. No one should feel comfortable with decisions regarding sharing and deadbands without understanding the actual risk that is being taken. Finally, putting off a decision on the real issues will be seen as rewarding the company for not providing a factual basis for its request.

CUB urges the Commission to reject the deferred account filing beyond the 3 percent that we recently approved.

CUB notes deficiencies in PacifiCorp's deferred accounting application. PacifiCorp projected that Oregon's share of the extra net power costs for the period for January 1, 2001, to December 31, 2001, would be $63 million. Application at 5. The filing says nothing about projected or actual costs for November and December of 2000 or the projected amount from November 2, 2000, to July 31, 2001, the requested life of the deferred account. The only data furnished in the application is the calculation of the $63 million and an example of an accounting mechanism to determine the deferred amount.

On January 18, 2001, PacifiCorp applied for approval of deferred costs equal to 3 percent of PacifiCorp's gross revenues in 2000 and to begin recovery of that $22.8 million in rates on February 1. PacifiCorp and Staff signed a stipulation in which Staff stated that it believed the amortization of the $22.8 million was appropriate. This filing contained no data explaining the potential exposure of customers from the deferred account or a full explanation of what caused PacifiCorp to be buying so heavily in this market.

CUB poses three questions to express its discomfort with PacifiCorp's application:

1. What is the company's actual and potential exposure to the market, both in terms of kWh and in terms of dollars the company is seeking to recover from ratepayers?

2. Why is this company, with its level of existing generation, so reliant on the wholesale market to serve its retail customers and whose responsibility are these costs?

3. What is the effect of load growth on Oregon rates?

CUB's discussion of the three questions:

1. What is the exposure? With respect to the first issue, CUB states that it has been unable to get a straight answer on the timing and extent of the company's exposure. CUB maintains that the Hunter and poor hydro circumstances postdate the company's filing for a deferral and make the filing look like a de facto power cost adjustment. A deferred accounting mechanism for a general cost category such as power costs, as opposed to a discrete item, will pick up all power costs over the established baseline, no matter how ordinary the costs are. In all other circumstances such costs are properly the utility's concern between rate cases.

CUB tried to determine how much money PacifiCorp was asking customers to pay. Before the first settlement conference, PacifiCorp had not supplied either actual net power costs for November and December or the forecasted costs for January through August. PacifiCorp orally provided the actuals and forecasts at the first settlement conference. The actual excess net power costs for December were given as $164 million. This figure was updated orally to $154 million at the second settlement conference. In response to CUB data request 9a, the actual costs for December had changed to $160 million. PacifiCorp provided another set of December actuals in an updated response to 9a at the settlement conference on February 13, $169 million.

The purpose of the deferred account was to recover excess net power costs caused by high wholesale power costs. Because PacifiCorp has enough generation in rate base to cover retail load, CUB was uncertain why the company was purchasing wholesale power. CUB believed the likely cause was that sales for resale contracts left the company short and needing to purchase power in a high priced market to balance requirements. In its reply comments, December 14, 2000, the company said that it had "mitigated (but not eliminated) its exposure to excess net power costs" and that "an upswing in wholesale power prices will result in further power cost increases." Reply at 9. This suggested that PacifiCorp remained short and needed to purchase additional power on the short term wholesale market. If the company was long, an increase in wholesale power prices would decrease net power costs.

CUB wishes to know how short the company was on November 1 when it made its initial filing, before the Hunter outage and the hydro problems. CUB's data request 1 asked: When PacifiCorp made this filing, what were its expected unfilled power needs by month from November 2000 through September 2001? The company answered the question by month on peak and off peak. The short position peaked in February and March of 2001. This was before the circumstances involving the Hunter plant and hydro conditions were taken into account.

Then, PacifiCorp told CUB that its response to CUB's data request 1 was wrong. The answer to data request 9a showed PacifiCorp was not short. PacifiCorp has a long position and selling this into the market is a benefit to customers. The real culprit was not an inherent system shortage but the need to fill the shortage caused by Hunter and hydro conditions. This raises questions of timing. CUB asks when PacifiCorp found itself long and why PacifiCorp made this filing in November, before Hunter went down and before the hydro conditions were known.

When CUB pointed out to PacifiCorp the conflict between answers to data requests 1 and 9a, PacifiCorp sent a supplemental response to CUB data request 1 and asked CUB to disregard its first response. PacifiCorp's supplemental response states that not only was PacifiCorp not short as of November 1, it had a "cumulative net position to the tune of 213,000 kWh." CUB notes, however, that the accompanying spreadsheets conflict with the covering prose. First, the 213,000 is in MWh, not kWh. Second, the spreadsheet shows that PacifiCorp was 213,000 MWh short, not long. And if one applies the spreadsheet to the period of the deferral, PacifiCorp is 785,788 MWh short. This was before the effects of Hunter and hydro.

The supplemental answer claims that on November 2, when PacifiCorp filed for this deferred account, PacifiCorp expected to have 7,010,882 MWh of resources in November and 6,288,211 MWh of resources in December, as compared to 6,571,125 MWh of requirements in November and 6,308,697 MWh in December. CUB compared this answer to a PacifiCorp fact sheet from late January showing actual net power costs. Comparing the resources PacifiCorp expected in November and December versus the actual production for those months (as provided at the end of January) shows that the only change from their projections was due to Hunter being out and hydro conditions being below normal. On the face of it, this seems to support PacifiCorp's newest argument that all its shortage is due to Hunter and hydro, but CUB also argues that, on the face of it, the details are unbelievable. PacifiCorp was able to predict in advance the output of every other facility down to a single megawatt hour, including its wind resources. CUB does not understand how a company can accurately predict the weather well enough to know in advance the actual output of wind facilities but fail to predict the lack of rainfall and its effect on hydro.

On April 2, CUB received what it considers an honest projection for November and December, made before the Hunter outage and the downturn in hydro conditions. PacifiCorp's thermal resources are responsible for a flexible generation system that can absorb the Hunter loss. For hydro, PacifiCorp exaggerated the amount of MWh that were lost. CUB believes that the power cost increases due to Hunter and poor hydro account for one third of the overall increase in net power costs. CUB asserts that the rest is due to wholesale contracts and load growth in other states.

2. Why is the company reliant on the wholesale market? CUB maintains that a few years ago, PacifiCorp was a regional company with international aspirations. Wholesale sales made an important contribution to both building market share and contributing capital for international purchasing. CUB sees three major problems with this trading activity. *First*, the price was too low. PacifiCorp distributed a fact sheet at the February 13 settlement conference for informational purposes, listing wholesale contracts between 1996 and 1998 and comparing these to PacifiCorp's 1996 avoided cost filing. However, PacifiCorp's Least Cost Plan in 1997 states that the company intended to rely on wholesale market purchases to serve these contracts. Since PacifiCorp intended to use market purchases to fill wholesale sales requirements, the proper cost comparison is the 2001 price of the contracts versus the expected 2001 wholesale market price of power, not the avoided cost based on PacifiCorp's embedded system.

Looking at wholesale sales contracts made between 1996 and 1998, the sales price was above PacifiCorp's cost of purchasing power in 1997 (meaning PacifiCorp could meet these contracts with wholesale short term purchases and make a profit), but the sales price was below the company's expected price of power in 2001 (meaning that by 2001 the company could no longer meet these contracts with short term wholesale purchases and make a profit).

Second, CUB argues that these contracts are very risky. In its 1997 least cost plan the company states that these contracts will allow the company to follow the strategy of relying on the wholesale market to acquire the resources needed to meet its wholesale contract commitments. But CUB contends that by relying on the short term purchases to back up long term sales, the company took a huge risk. If the cost of short term wholesale power went up, the company would lose money. The least cost plan also showed that the company realized that market prices could go up. The company considered what would happen to market prices if the price of natural gas increased. PacifiCorp projected that a 50 percent increase in gas prices would push wholesale purchase prices up to 29.7 mills in 2001 and a 100 percent increase in gas prices would push wholesale prices up to 40.7 mills in 2001. Least Cost Plan p. 41, adjusted for inflation. PacifiCorp won its gamble for a while, but when the market changed, the gamble became a loser. Now, CUB argues, PacifiCorp wants a deferred accounting that shifts losses to customers.

Third, the critical question for CUB is: Between rate cases, who should pay for wholesale losses? PacifiCorp asserts that it asks for the same treatment these contracts have historically received—that earlier rate cases included benefits from sales for resale contracts and now that these are losing money, customers should also bear the losses. But this is not a traditional rate case. The appropriate treatment for wholesale losses in a traditional rate case will likely be an issue in UE 116.

CUB argues that losses between rate cases should be treated the same way as gains between rate cases have been treated. Historically, these gains have flowed to the company. CUB believes that many of these contracts were signed in a period between rate cases specifically so PacifiCorp could use the gains for its international expansion. CUB believes PacifiCorp made significant profits on these contracts between rate cases when it was profitable to do so and now is trying to pass losses from the same contracts on to their customers.

3. What is the effect of load growth? CUB believes that Hunter and hydro account for $81.9 million of PacifiCorp's power cost losses; wholesale contracts account for $157.7 million; and load growth accounts for $25 million. Utah's load is 10.9 percent greater than expected, and CUB argues that Oregon should not have to pay higher rates between rate cases because of load growth in another state. Moreover, CUB argues that the open ended deferral mechanism proposed by Staff would force Oregon customers to pay for Utah's summer peaking, and Utah customers have no incentive to conserve.

CUB's Proposal. CUB believes that the company should normally bear the burden of changes in its generation output between rate cases. However, if those costs are significantly outside normal circumstances and affect the company's financial health, customers should reasonably be asked to absorb a share of the extraordinary costs. CUB notes that there is nothing on the record pertaining to the company's financial health.

CUB urges the Commission to limit deferral to the effects of a reduction in company owned generation due to Hunter and hydro conditions that are outside of normal operating circumstances. CUB proposes the following deferral formula:

Deferred amount equals change in generation output from what was projected each month times (average price of short term firm power company purchases that month minus average price of short term firm power company purchases in the same month of a normal year) times Oregon's share of actual retail load for that month.

CUB's Discussion of the Issue List: CUB answers in general that there is insufficient information in the record in this case to provide answers. CUB does provide responses to a few of the issues, set out below.

5. Should there be a cap? Given the uncertainty of the cause of the company's exposure and the huge risk PacifiCorp is demanding that customers take, CUB thinks that a cap is necessary: equitably, politically, and financially.

6. Should a sharing mechanism be based on actual states' loads? CUB responds yes. PacifiCorp is asking the Commission to make Oregon customers pay 32.9 percent of excess net power costs. CUB 9a shows that PacifiCorp projects Oregon as 29.3 percent of the retail load during this period. Comparing this with CUB data request 1 supplemental, PacifiCorp is predicting Oregon's load to be 22.3 percent of PacifiCorp's total requirements, wholesale and retail, and PacifiCorp's net power costs are designed to fill total requirements, not just retail load. In addition, there is a significant risk that a hot summer in the Southwest could cause Oregon's load to be significantly less than the company projects. PacifiCorp offers no justification for asking Oregon customers to pay for more than our share of load.

7. Are there alternative mechanisms to consider? CUB believes that the Commission should deny this application altogether and wait for the rate case to address power cost issues.

10. Should there be different mechanisms for different utilities? CUB answers yes. Otherwise this turns into a general policy docket, and PGE should participate. Each utility is different.

Wah Chang's Position. Wah Chang also argues that the Commission should deny PacifiCorp's application for deferral. According to Wah Chang, PacifiCorp has not substantiated its theories of deferral with any data of actual harm. Wah Chang takes issue with each of the theories for PacifiCorp's higher power costs.

Broken Markets: PacifiCorp's current rates from UE 111 do not reflect the current extraordinarily high prices in the western bulk power market, but there is no evidence that PacifiCorp has suffered from that market or if it has, that it was prudent for PacifiCorp to be in a position to suffer. The record in this proceeding does not reveal PacifiCorp's complete trading activity, without which it is impossible to verify PacifiCorp's announced distress. According to Wah Chang, PacifiCorp must prove actual impact.

Wah Chang argues that the papers filed to date show that any net power cost revenue deficiency is due to PacifiCorp's need to serve special wholesale contracts, not retail load. Wah Chang argues that only about 1/7 of the market supply needed to reach load/resource balance in November/December was necessary to meet retail load. Further, PacifiCorp's papers show that it was forced to buy short term at high prices ($82/MWh, on average for November; $134 for December) and sell at low, locked in contract prices ($37/MWh for November, $41 for December). Wah Chang infers that not one of these contracts is interruptible or reachable for a rate increase by this Commission.

According to Wah Chang, the critical question about these wholesale contracts is whether they are prudent in their collective magnitude. In November and December 2000 (the only actuals), PacifiCorp was compelled to purchase an average of 2.2 million MWh/month on the short term market to serve load, but only .3 million, or 1/7, of that was necessary to serve retail load. Of the average retail system load in November and December, 4.7 million MWh, the company could not supply a reserve capacity of even 7 percent without going to the short term market because wholesale contract commitments got in the way. System resources are likely being carried in rate base, and rates of return are being earned on something greater than an assumed reserve capacity of 7 percent. System resources are being run for the benefit of wholesale customers who are not bearing the full cost of whatever excess cost PacifiCorp is incurring.

Poor Hydro. Wah Chang doubts the assertion of any actual hydro deficiency in November and December, but PacifiCorp uses this as the sink into which its profit from market prices was lost, turning positive system revenues of $136 million in December into a loss of $219 million, $72 million of that just for Oregon.

Load Growth: Wah Chang dismisses this assertion out of hand as de minimis. Its impact on the company's net power cost, if any, is submitted for the first time in PacifiCorp's

February 13 submission and is wholly swamped by the category of costs with which it is merged, market prices.

Hunter #1 Outage: This line item reflects the cost of replacing power lost because of the Hunter outage on November 24. It is a big number, $20 million (over $450/MWh) in December just for Oregon, theoretically priced at PacifiCorp's forward electric cost curve on the day of loss or the day after. But Wah Chang questions the accuracy of the numbers. Wah Chang did not receive an answer to its data request about PacifiCorp's forward curve on the day after Hunter went down. PacifiCorp's actual average cost of short term firm power for December was $134. PacifiCorp's average system cost of power for December was $33.50/MWh.

Hunter #1 is not needed for PacifiCorp's system retail load. In December, system resources exceeded system retail load by 364,000 MWh and exceeded the lost Hunter #1 supply by more than 90,000 MWh. Wah Chang asserts that PacifiCorp was operating Hunter #1 to cover its special wholesale contract commitments, the noninterruptible ones that consume all PacifiCorp's reserves.

What is bothersome about covering wholesale contracts with system resources, according to Wah Chang, is that ratepayers paid for a reserve and paid a rate of return on the reserve, without getting the benefit of it. Hunter, part of the presumed reserve, was not in reserve at all because its loss had to be replaced with market power to serve those wholesale contracts at the sole expense of retail ratepayers.

Wah Chang also argues against setting a baseline in this proceeding, because there is no known objective nexus to the last general rate case, UE 111. Any presumed baseline would have to be arbitrarily assigned. PacifiCorp needs to start over. Wah Chang argues, finally, that PacifiCorp has not carried its burden for a deferred accounting order, let alone rate amortization. Its submission is conclusory, ever changing, and contradictory. Wah Chang concludes that the deferral should be denied, the amortization terminated, and the collected rates refunded with interest.

ICNU's Position. ICNU opposes PacifiCorp's application for an accounting order regarding excess net power costs in excess of those already approved in Order No. 00-186.

According to ICNU, it is premature to brief issues in this proceeding, because there is no factual record. The following major facts remain at issue in this case:

1. Do the revenues set in UE 111 cover PacifiCorp's actual power costs to serve its Oregon native load customers, or are these alleged excess power costs due to imprudent wholesale sales?

2. What are the precise reasons that PacifiCorp is allegedly unable to cover its monthly power costs with current revenues?
3. What are PacifiCorp's actual monthly excess power costs since this application was filed in November?

4. Is PacifiCorp seeking to recover power costs that should be included in its "normalized power costs"? In other words, are any of these costs attributed to low hydro or generator outages, for instance, which are already normalized in PacifiCorp's power cost models?

5. Are these excess net power costs attributed to poor power supply management by PacifiCorp, including whether PacifiCorp properly hedged its wholesale transactions?

While parties to this docket have submitted many data requests, ICNU notes that they do not have all the answers at this time. In reviewing the documents provided to CUB, the responses to the data requests seemed to change on a weekly basis.

ICNU's Discussion of the Issues List:

1. What components should be included in the deferred account? ICNU does not believe that PacifiCorp has shown it is entitled to any further deferrals beyond the $22.8 million already approved by the Commission. Specifically, ICNU argues that the following costs should not be approved:

a. Losses associated with wholesale power transactions;
b. Low hydro (in the utilities' power supply models, rates are set based on normalized hydro conditions and a utility bears the risk of poor hydro years and receives the benefit of good hydro years);
c. Costs due to plant outages (these are also normalized in the power cost model used in prior cases);
d. Any revenues PacifiCorp is seeking in UE 116 that would in effect lead to double recovery;
e. Any lost revenues associated with PacifiCorp's inaccurate load growth assumptions in UE 111 (PacifiCorp maintained in UE 111 that its load growth would be 2.33 percent (PacifiCorp Resource and Market Planning Program, 5 Dec. 1997, chapter 4, pp. 105-106). PacifiCorp now asserts that it is experiencing high load growth, at approximately 10 percent in Utah, which is contributing to its power cost problems);
f. Any imprudently incurred costs;

g. Any costs not associated with serving its Oregon customers; and
h. Any costs that could be offset by Transition Plan savings.

2. What is the appropriate baseline? UE 111 resulted in a black box settlement and did not identify PacifiCorp's specifically approved power cost levels. In UE 111, several proposals were made to disallow certain costs. Use of a baseline and a deferral mechanism that do not account for disputed fuel items might effectively allow the company recovery of costs it previously conceded. A baseline, thus, should be established independently in this proceeding.

3. Should the mechanism have a deadband? The deadband should apply only to properly deferred amounts and amounts associated with costs to serve Oregon customers. In other words, a deadband should not be used to justify allowing deferral of the costs identified above.

5. Should there be a cap? ICNU says yes, and that the cap should be the already approved $22.8 million. Under no circumstances should a deferral exceed the $63 million estimated in PacifiCorp's application.

6.-10. Issues surrounding the mechanism. According to ICNU, the difficulty is that PacifiCorp has already proposed a mechanism, deferred accounting, but is unhappy with the 3 percent annual recovery limitation contained in Oregon law. Thus, PacifiCorp seeks to treat this application in a different manner. ICNU has maintained from the beginning that this application looks more like a PCA than a deferred accounting mechanism. The fact that Commission Staff filed its proposal for a power cost adjustment mechanism on January 5, 2001, suggests that Staff also believes that the underlying issues in this case are similar to a PCA. But the Commission cannot and should not impose such a mechanism in this case. PacifiCorp needs to file independently for such a mechanism. This will lead to a proper consideration of a PCA mechanism rather than indirectly addressing the issue through a deferred accounting application.

Another problem with PacifiCorp's proposal is that it is one sided. If market prices fall substantially in the future, or PacifiCorp moves to a surplus position, its net power costs could decline dramatically. There is no mechanism in place to force PacifiCorp to flow through savings in such cases, that offsets the risk of higher costs now.

A PCA could address this problem. The Commission, however, has found several inherent flaws with PCAs. First, they do not provide incentives for utilities to minimize power costs. As a result, regulators often employ a sharing mechanism to create an incentive to reduce costs. Re PGE, UM 529, Order No. 93-309. Second, PCAs shift the risk of power cost volatility to ratepayers. Re Wash. Water Power Co., WUTC Docket No. U-882362-P, First Supp. Order, September 18, 1989. This type of risk shifting is inappropriate unless there is an explicit reduction in the utility's cost of capital to reflect the reduced risk to the utility. *Id*. Finally, PCAs create difficult issues of measurement, because increased power market prices often create opportunities for increased sales for resale, which should be accounted for in the PCA.

In addition, states that allow PCAs often have strict rules regarding allowable costs for PCA recovery. Unless the Commission were to engage in a proceeding to establish such rules, ICNU fears that the end result will be one sided. While PacifiCorp may choose to pursue a PCA, ICNU does not support this approach. This uncertainty is acute in PacifiCorp's proposal, because the application provides no specific description of the method for calculating PacifiCorp's actual net power costs during the deferral period. However, PacifiCorp's proposal also does not include any of these safeguards. Therefore, under PacifiCorp's approach, ratepayers would shoulder the entire risk of PacifiCorp's management of its market transactions without any Commission oversight.

Moreover, the Commission should provide appropriate incentives for PacifiCorp to minimize its net power costs. PacifiCorp's UM 995 application shifts the risk of power cost fluctuations away from the utility and onto ratepayers. Absent a deferred account or PCA, PacifiCorp's shareholders are solely responsible for fluctuations in variable costs between rate cases. Under PacifiCorp's UM 995 application, the entire risk of PacifiCorp's decisions in the wholesale power market will be borne by ratepayers. By deferring the entire difference between PacifiCorp's anticipated and actual power costs, PacifiCorp has no risk and, therefore, no incentive to control its costs. The reward for PacifiCorp's failure to adequately control its power costs should not be a blank check to spend ratepayer money.

Utilities have not used the deferred accounting statute to shift all of the risk of operations onto ratepayers or to control their costs. Re PGE, Docket UE 82/UM 445, Order No. 93-257; Re PGE, UM 529, Order No. 93-309. The Commission has acknowledged that deferred accounts can "depart from the normal risk-reward assumptions by utilities." Order No. 93-257. To reduce opportunities to shift risk, it is appropriate to impose conditions on deferrals. Order No. 93-257; Order No. 93-309; Re PacifiCorp, UE 76, Order No. 92-1128 (interpreting ORS 757.259(2)(c), subsequently renumbered without revision ORS 757.259(2)(e)).

CUB and ICNU have filed a complaint and request for hearing in this docket. ICNU argues that the complaint must be resolved before the Commission rules on PacifiCorp's deferral application. In their complaint, CUB and ICNU raise several legal issues, set out below:

First, PacifiCorp's net power costs were not prudently incurred on behalf of Oregon ratepayers and should not be placed in a deferred account. PacifiCorp should not be permitted to place expenditures in a deferred account that are not expected to be included later in rates. PacifiCorp is only permitted to place in rates deferred amounts that were prudently incurred on behalf of Oregon retail ratepayers. UM 954, UM 958, Order No. 00-308 at 1; see Re U S WEST, UT 125, UT 80, Order No. 00-191. A significant portion of the net power costs PacifiCorp is attempting to defer are not prudent or do not benefit Oregon ratepayers and therefore should not be placed into a deferred account.

Second, ongoing excess net power costs that are incurred for a variety of unspecified reasons do not constitute discrete costs as required by ORS 757.259(2)(e). Deferrals under ORS 757.259(2) are authorized only for "discrete items which might substantially affect a utility's earnings on a short term basis." Re PacifiCorp, UE 76, Order No. 92-1128 at 8. Discrete costs refer to specific events, including expenditures related to particular litigation expenses, energy efficiency investments, replacement power costs, and corporate reorganization. Re Idaho Power Co., UM 769, Order No. 95-1262; Re PGE, UM 538, Order No. 93-346; Re PGE, UM 529, Order No. 93-309; Re PGE, UM 246, Order No. 90-311.

PacifiCorp's net excess power costs are not discrete, short term expenses incurred in relation to a specific event. PacifiCorp has failed to specify the actual amounts or causes for its deferred accounting application other than a general reference to high market prices. PacifiCorp does not identify particular expenses or provide a definitive method for power cost calculation but only seeks deferral of general power cost increases. In addition, PacifiCorp has not presented evidence that allows the Commission to ascertain the actual causes of PacifiCorp's increased net power costs. Without further factual inquiry the Commission cannot determine that the costs PacifiCorp seeks to defer are discrete.

Third, the application does not match ratepayer costs and benefits as required by the deferred accounting statute. The Commission is authorized to defer amounts in order to match ratepayer costs and benefits. (2)(e). This provision was included to authorize the Commission to defer costs associated with programs that have long term benefits. Deferred accounting statute: Hearing on HB 2145 before the House Committee on Energy and Environment, Exhibit B at 8 (1987) (testimony of PUC Commissioner Davis). The concern was that certain "measures would produce benefits lasting for some time. It seemed inappropriate to charge costs only to ratepayers at the time the . . . expenses were incurred." *Id*. Granting PacifiCorp's UM 995 application will not appropriately match a long term utility expenditure with future ratepayers it is intended to benefit since these expenditures cover current monthly power costs.

The Commission has recognized that matching ratepayer costs and benefits must be related to each other and the utility's costs must accrue today, but the benefit must flow to future ratepayers. Re PacifiCorp, UE 76, Order No. 92-1128 at 9. When future customers derive the benefit from current costs, Oregon law permits the current expenditures to be deferred and placed in rates at the time the benefits flow to ratepayers. If current ratepayers are not paying the costs of benefits that accrue to future ratepayers, then a deferral cannot match ratepayer costs and benefits. PacifiCorp's application cannot satisfy this standard.

ICNU requests that the Commission deny the remaining portion of PacifiCorp's application in UM 995 or defer ruling on the application until a full and proper factual record has been developed in this proceeding or in UC 578.

Commission Discussion and Disposition. The parties opposing this application share a concern about the deficiency of the factual record. We do not consider the factual record inadequate to grant an application for deferral. Deferral is only the first stage in PacifiCorp's eventual recovery of its excess net power costs. PacifiCorp must also subject its excess net power costs to a prudence review, which will generate a factual record. Before we approve amortization of the deferred amounts for inclusion in rates, we will conduct an evidentiary hearing that includes a prudence review. Should the factual record there be inadequate, the amortization will not be granted and PacifiCorp will fail to recover any of the costs it applies to defer. We believe that this procedural step addresses many of ICNU's, Wah Chang's, and CUB's concerns.

The UC 578 Complaint. ICNU argues that we cannot proceed with this application until we process the complaint it filed with CUB against PacifiCorp (UC 578). We disagree. The complaint is lodged against PacifiCorp's application in UE 121, pursuant to ORS 757.210. That is, it properly pertains to the amortization of deferred amounts, for which PacifiCorp filed an application in UE 121.

ICNU lists three legal issues that it considers obstacles to processing this application. First, ICNU states, PacifiCorp's net power costs were not prudently incurred. We believe that the prudence review scheduled to precede amortization adequately addresses this concern. Prudence is not an issue for this deferral docket.

Second, ICNU contends that ongoing excess net power costs incurred for a variety of unspecified reasons do not constitute discrete costs as required by ORS 757.259(2)(e). In Order No. 01-085, we deferred a discussion of whether the costs for which PacifiCorp requests deferral were discrete or not, pending a discussion among the parties about Staff's concerns. The parties did not resolve this issue.

We note that the requirement of "discrete" costs arises not from the statute but from UE 76, Order No. 92-1128, at 8, where we stated: "*For the most part*, deferrals under ORS 757.259(2)(c) [now (e)] were to be of discrete items which might substantially affect a utility's earnings on a short term basis" (emphasis supplied). The language of the statute does not preclude granting PacifiCorp's application, and the discussion in UE 76 does not impose an absolute requirement of discrete costs in a deferred accounting application. We do not accept ICNU's argument about discrete costs.

Third, ICNU repeats an argument it and CUB made earlier in this docket, which we answered in Order No. 01-085. ICNU argues that PacifiCorp's application does not match ratepayer costs and benefits as required by the deferred accounting statute. ORS 757.259(2)(e) states:

> (e) Utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

We said in Order No. 01-085 that the requirement of matching ratepayer costs and benefits is stated in the alternative with minimizing the frequency of rate changes or the fluctuation of rate levels. That is still the case. We believe that granting this application will minimize the frequency of rate changes or the fluctuation of rate levels, as we stated in our earlier order.

The PCA Issue. CUB and ICNU express concern that the Commission not impose a PCA in this docket, without a specific filing requesting such a mechanism. We agree that it would be inappropriate to impose a PCA without an explicit filing asking for such a mechanism and proper consideration of the mechanism. PacifiCorp filed for a PCA on March 23, 2001, in docket UE 122. When that docket is processed, we will fully address the issues surrounding power costs adjustments. We will not decide on a PCA in this docket.

ICNU and CUB also argue that the filing in this docket is similar to a PCA and should therefore be denied. They point out that the proposed mechanism would capture and allow PacifiCorp to recover a percentage of all power costs, regardless of their cause. We understand the parties' concern but believe that the deadband and the sharing mechanism protect ratepayers. We cannot amortize more than we here authorize PacifiCorp to defer.

The Deferral. ICNU, CUB, and Wah Chang all oppose allowing PacifiCorp any deferral beyond the $22.8 million already approved or, in CUB's case, beyond extraordinary power costs due to Hunter and poor hydro. PacifiCorp argues for a more generous recovery mechanism and Staff for a recovery mechanism that is somewhat less generous than PacifiCorp requests and that imposes sharing on PacifiCorp. We conclude that Staff's proposal is the best choice.

The opposing parties point out that between rate cases, the utility typically bears the risk of increased power costs. In the normal case, that is an accurate statement. The current power market, however, in conjunction with the Hunter outage and poor hydro conditions, creates a situation that is beyond the normal. In this extraordinary situation, we believe that PacifiCorp should have an opportunity to recover some of its excess power costs.

We prefer Staff's mechanism to PacifiCorp's, however. PacifiCorp's model is structurally similar to Staff's but is more generous to the company. Staff's is more generous to ratepayers. We find that Staff's model balances the interests of the company and ratepayers in a more appropriate way.

We therefore elect to adopt Staff's recommendations about a deferral mechanism. We also, with one exception, adopt Staff's responses to the issues list. In response to the problem of PacifiCorp being a multi jurisdictional company, we choose Staff's Option 1: Revise the sharing percentage over 400 basis points from 90/10 to 75/25 for customers/company.

The issue for which we do not adopt Staff's recommendations is with respect to Issue 2: What is the appropriate baseline? The factual record in this docket does not permit us to resolve the question of the appropriate baseline. We direct the parties to meet and within 30 days of the issuance of this order either submit an agreement on the baseline or submit briefs addressing the issue.

The mechanism proposed by Staff, which we adopt, will limit the amount of excess power costs deferred. When we address amortization of the deferred amounts, we will consider whether this same mechanism will be applied to the amount to be amortized. Parties will be able to argue for this or a different mechanism during the hearing on amortization.

ORDER

IT IS ORDERED that:

1. PacifiCorp's application to defer excess net power costs is approved subject to the deferral mechanism adopted in this order.

2. The deferral mechanism proposed by Staff is adopted, with Staff's Option 1, 75 percent borne by customers and 25 percent borne by the company, being adopted for sharing over 400 basis points.

3. Parties to this docket shall meet to set a baseline on which the deadband and sharing bands will be based. Parties shall submit an agreement on the baseline within 30 days of issuance of this order. If parties are unable to reach agreement on the baseline, they shall submit briefs on the issue within 30 days of issuance of this order.

Made, entered, and effective ________________________.

____
Ron Eachus
Chairman

____
Roger Hamilton
Commissioner

____
Joan H. Smith
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. The request must be filed with the Commission within 60 days of the date of service of this order and 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.