BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

	)	
In re the Petition of	)	
	)	
PACIFICORP d/b/a PACIFIC POWER	)	DOCKET NO. UE-020417
& LIGHT COMPANY	)	
	)	
For an Accounting Order Authorizing	)	
Deferral of Excess Net Power Costs.	)	
	)	
. . . .	)	

POST-HEARING BRIEF OF COMMISSION STAFF

April 11, 2003

TABLE OF CONTENTS

I.

INTRODUCTION

1 PacifiCorp requests authority to defer "excess net power costs" from June 1, 2002 to May 31, 2003 (Deferral Period). The Company seeks to recover those costs immediately by eliminating the Centralia and Scottish Power merger credits received currently by ratepayers.

2 The Commission Staff recommends rejection of the Company's proposals. *Irrespective of the Rate Plan Stipulation*, the Company's proposal defers changes in power costs that were not incurred to serve Washington ratepayers. PacifiCorp also assumes a flawed power cost baseline and tracks all changes from that baseline, rather than only extraordinary changes related to the 2001 western power crisis. (Section II.)

3 The Company also failed to demonstrate that it is entitled to rate relief under the *PNB* standards. The Company's presentation of Washington stand-alone financial conditions is *meaningless* because it is based upon an obsolete cost allocation methodology that has not been accepted for ratemaking purposes in Washington and that allocates to Washington the cost of new generation that is not required to serve Washington. (Section III.) The Company's presentation of Washington stand-alone financial conditions is also *irrelevant* because the

Company is currently able to access capital on reasonable terms in order to satisfy its public service obligations. (Section IV.)

4 The Company's proposals also violate the express terms of the Rate Plan Stipulation. Amending the Rate Plan Stipulation is not warranted by the public interest. (Section V.)

5 The discussion that follows elaborates on these points. That discussion also demonstrates that no inequity would ensue if the Company's proposal is rejected.

II.

THE PROPOSED DEFERRAL MECHANISM IS FLAWED, OVERBROAD, AND ASSIGNS TO WASHINGTON RATEPAYERS COSTS THEY DID NOT CAUSE

6 In its analysis of the Company's proposals, Staff considered the Rate Plan Stipulation and the commitments made by all parties to that agreement. However, the Rate Plan Stipulation was not the primary driver in Staff's analysis. Staff was motivated first and foremost by its responsibility to assist the Commission in regulating in the public interest the rates, services and practices of utilities subject to the Commission's jurisdiction. RCW 80.01.040(3). This is a continuing obligation that Staff must satisfy even if it is necessary to amend an order adopting a settlement without the consent of all parties to that settlement.

7 Thus, Staff analyzed the Company's proposal as if the Rate Plan Stipulation never existed. Staff also assumed that the power costs PacifiCorp seeks to defer are prudent on a system-wide basis. And, Staff assumed that costs associated with forward summer peaking contracts are extraordinary. (Tr. 499-500, 565, 576-77 and 581-82.)

8 Nevertheless, Staff revealed the following flaws in PacifiCorp's case.

A. The Commission Should Reject the Deferral Mechanism Proposed by PacifiCorp; That Mechanism Assumes a Flawed Baseline and Tracks All Changes In Power Costs Rather Than Only Extraordinary Costs Associated With the Power Crisis

9 The Company proposes to defer "excess net power costs." In order to calculate the deferral, PacifiCorp subtracts its "base net power costs" (Base NPC) from its "actual net power costs" (Actual NPC). The Base NPC is the power supply expense level that PacifiCorp proposed in its 1999 general rate case in Docket No. UE-991832 (1999 Rate Case). The Actual NPC includes all long-term firm purchases, short-term purchases, wheeling expenses, and thermal fuel expenses. (Ex. 115 at 5: 5-10 and 11: 18-20.)

10 The Commission should reject this approach. It is inappropriate to the use as a baseline for deferrals the Company's power costs that it filed in the 1999 Rate Case. The Company's proposal also tracks *all* variations in power supply expense, rather than only extraordinary changes related to the 2000-2001 western energy crisis.

1. The Proposed Baseline Does Not Reflect a Level of Power Costs Embedded in Rates

11 The Base NPC is a critical component of the Company's deferral mechanism. The Company uses as the Base NPC the power supply expense level ($486 million) that it proposed in the 1999 Rate Case.

12 However, there was no agreement among the parties in that case, nor a finding by the Commission there or in a later proceeding, of any specific level of power supply costs in rates or any method for determining one. (Ex. 115 at 3: 13-17; Tr. 174.) The Commission stated expressly that the Rate Plan Stipulation ". . . would not establish benchmarks against which to measure financial performance. . ." *WUTC v. PacifiCorp*, Third Suppl. Order at ¶58, Docket No. UE-991832 (August 2000). (See also Ex. 103.) The Company agrees that current rates do not reflect the proposed baseline:

13
> Because in the last Washington rate case, Docket No. UE-991832 (1999 Rate Case), was settled pursuant to the Rate Plan Stipulation, there was no specific finding regarding the level of net power supply costs reflected in base rates.

14 (Ex. 57C at 2: 8-11.) Thus, there is no reason to conclude that the power supply expense level filed by the Company in the 1999 Rate Case is an appropriate baseline for deferrals.

15 In fact, these is every reason to conclude that a litigated result in the 1999 Rate Case would have reflected a different level of power supply expense than

the level the Company proposed in that proceeding. That is because many significant power supply issues were left outstanding in the 1999 Rate Case to be resolved after the Company's transition period in the post rate plan earnings review. (Ex. 2 at ¶3; Tr. 550-53.) These issues included:

- the appropriate power supply model to use
- the appropriate water record to use for normalized hydro-electric power availability
- price issues related to specific wholesale contracts
- the appropriate levels of normalized thermal generation
- fuel price issues
- short-term sales and purchase prices

16 In addition, left unresolved were issues associated with new resources, the Company's strategy associated with wholesale market participation, and the long-term replacement of power as a result of the Centralia sale. The lack of an approved inter-jurisdictional cost allocation methodology served to intensify the uncertainty regarding the level of power supply costs that would have been reflected in rates in a contested case. (Ex. 115 at 7-10.)

17 The Company defends the Base NPC as "very reasonable" because the agreed increases under the Rate Plan are less than half of what it requested in the 1999 Rate Case. (Ex. 57C at 3: 8-10.) The Company also claims that the $486

million baseline is "conservative" because the use of any lower number would produce higher deferrals. (Ex. 115 at 10: 13-20.)

18 This defense, however, is toothless. A lower baseline would not necessarily result in higher deferrals. That is because Washington's share of any lower baseline would need to be based on an appropriate cost allocation methodology. No such methodology now exists.

19 Moreover, the unresolved power supply issues from the 1999 Rate Case also impact the Actual NPC. Thus, even if a lower baseline were incorporated, the calculation of a deferral would not necessarily result in a larger balance. (Ex. 115 at 11: 1-7; Ex. 118.)

20 The Company assumes that a lower level of power costs than what it proposed in the 1999 Rate Case would have resulted had the unresolved power supply issues been resolved in that case. That claim is inaccurate. At the time of the negotiations in the 1999 Rate Case, Staff had not finalized its power supply analysis. Staff was considering a wide range of positions and adjustments that would impact the level of normalized power supply expense in Washington. (Exs. 39, 40, 41, 116 and 117; Tr. 550-53.)

21 Thus, it is pure speculation whether Staff's final analysis, or a Commission decision, would have resulted in an increase or a decrease in normalized power costs for the Company's Washington operations.

22 Finally, the Company provided projections of power costs for fiscal years 2003 through 2006 to show that power costs are expected to stay at higher levels than the baseline used in the deferral calculation. (Ex. 8: 4-6 and Ex. 61C.) These projections are irrelevant. They do not relate to the Deferral Period. They do not support interim rate relief. (*See* Section IV, *infra*.) They also raise the specter that the Company may later seek additional deferrals if it is successful in this proceeding.[1] (Ex. 120, Part a.; Tr. 554.)

23 Moreover, the bases for the projections are the expiration of wholesale contracts, increased retail load, the denial of the sale of California properties, and contractual costs increases. (Ex. 57C at 8-10.) All of these are factors that the Company should have considered prior to entering the Rate Plan Stipulation.[2] (Ex. 115 at 27: 11-13.)

---

[1] The commissioners questioned the Company on this exact point. (Tr. 347-50.)

[2] For example, the Company maintains that the revenue credit from recently expired wholesale contracts is gone (thus increasing net costs) because the freed-up resources are being used to meet higher load obligations. (Ex. 57 at 8: 16-23.) However, it is not uncommon for wholesale contracts to expire since they are entered to address "lumpiness" in new resource additions. Thus, it should be expected that the power will eventually be needed by retail load growth. The Company's explanation also ignores the revenue side of the equation. As wholesale sales contracts expire, they are replaced by increased retail load at higher margins than the expiring wholesale sale. (Ex. 115 at 27: 16 through 28: 10.) Indeed, the Company states that the power was used to serve increased retail load. (Ex. 57C at 8: 18-20.)

The Company's explanation regarding increased retail loads is also unconvincing. The Company prepared a load forecast contemporaneously with the 1999 Rate Case. (Ex. 77.) It included various projections of retail load growth. Clearly, the Company was well aware of its future retail load growth responsibilities prior to entering the Rate Plan Stipulation. (Ex. 115 at 28: 13-18.)

24 In sum, the Company's proposed baseline for deferrals ignores the undisputed fact that there was no specific finding or agreement in the 1999 Rate Case regarding any level of net power costs currently in rates. There were also many issues regarding power supply expenses that were deliberately left unresolved and remain unresolved. There is simply no basis to conclude that rates reflect power supply costs at, below, or above Company filed amounts from the 1999 Rate Case.

2. The Company's Proposal Should Be Rejected Because It Defers All Changes In Power Supply Costs During the Deferral Period

25 The Company seeks "limited relief" to accommodate the lingering effects of the 2000-2001 western power crisis. (Ex. 1 at 5: 19-22.) The Commission, however, established a stricter standard. It stated that:

> [W]e expect the Company's evidence to address the questions of whether, and to what extent PacifiCorp's power costs *during the relevant period are extraordinary* relative to the power costs asserted to be embedded in rates for recovery . . . (Emphasis added.)

In re the Petition of PacifiCorp, Third Suppl. Order at ¶ 18, Docket No. UE-020417 (Sept. 2002).

26 The Company identified only one source of power costs that meet that standard: the forward purchases for summer 2002 that were made in the spring

of 2001 prior to the June 2001 price cap order of the Federal Energy Regulatory Commission (FERC).[3] (Tr. 563.) The Company states:

> In terms of the deferral period, prior to June 2001, the Company hedged against potential market price risk at prices much higher than historical norm, but less than the then current forward price curve to cover the usually high resource requirements of the 2002 summer peak period.[4]

(Ex. 74, Data Request 8 cover page.) Nevertheless, the Company's proposal goes well beyond deferring costs that are related to the forward summer peaking contracts, specifically, or even to the western power crisis, generally. (Tr. 563-64 and 569.)

27 The Company proposes to defer changes in its net power costs using actual expenses, including all long-term firm purchases, short-term purchases, wheeling expenses, and thermal fuel expenses. (Ex 115 at 11: 18-20.) Thus, every long-term wholesale sales contract that expired since the 1999 Rate Case has been removed and replaced by other contracts. (Tr. 327-28.) Those contracts that have remained in place are adjusted by their actual usage and prices. (Ex. 115 at 14: 2-6.)

---

[3] The Company states that the impacts of the power crisis were exacerbated by the 2000-2001 drought and the extended outage of the Hunter generating facility. (Ex. 1 at 5: 10-13.) However, the cost of these events pre-date the Deferral Period.

[4] The forward peaking contracts represent 400 MWs of power during peak high load hours at an average price of $151.5 per MWh. They are roughly $56 million out-of-the-market system-wide, based on March 2002 market prices. (*Id*. at Data Request Attachment.)

28 The same is true for all purchased power expenses. All new wholesale purchase power contracts have replaced old contracts, while those remaining are updated using actual usage and prices.

29 The Company's proposal incorporates actual short-term sales and purchase amounts and prices, as well as actual hydro generation and thermal generation, including actual fuel costs. Finally, other power supply expenses, such as wheeling and fuel expenses, are based on increased costs that result from contractual escalations. (Ex. 115 at 14: 6-12.)

30 The all-encompassing breadth of the Company's proposal is best seen in the specific calculation of the deferral. Exhibits 60 and 160 illustrate that calculation. They are based on Exhibits 58 and 59C. (Tr. 327-28.) The forward summer peaking contracts are included on only one line of these multi-page exhibits. (Ex. 59C at 2, line "STF"; Tr. 328.) Yet, a change in any other line item will change the deferral amount. (Tr. 329.) Thus, changes in costs unrelated to the western power crisis would be deferred by the Company under its proposal.[5]

31 The Company's proposal also is a significant departure from the normalized power supply expense methodology used in general rate cases. (Ex. 115 at 15: 3-4.) In a general rate case, a normalized power supply expense level is

[5] Just a few examples of these changes include increased costs associated with the Hermiston purchase, the Mid-Columbia purchase, any of the Company's various QF purchases, and any of the Company's various other thermal resource purchases.

determined that reflects the variability of hydro-generation conditions throughout the region and the Company's resource portfolio. This includes the likelihood of a drought. (Tr. 572.) A detailed review is performed of Company power supply resources, including long-term and short-term wholesale contracts, and secondary market price projections. The models used to derive normalized power are also evaluated, including the proposed methodology to incorporate the water record into the analysis. (Ex. 115 at 5: 14 through 6: 2.) The Company's proposal short-cuts all of these important analyses.

32 Variations in actual power supply expenses are also a standard element of normalized ratemaking. It is inappropriate to allow the Company to simply defer the difference between normal and expected variations in power supply expense.

33 Moreover, when the Company entered the Rate Plan Stipulation, it knew that wholesale sales and purchase contracts will expire, that most wholesale contracts have price escalation clauses, that hydro generation varies from year-to-year, that short-term sales and purchase amounts and prices vary, and that changes in wheeling and fuel expenses occur due to usage and contractual price changes. (Ex. 75 ; Ex. 115 at 15: 3-12.) Thus, other than the forward summer peaking contracts, there is no evidence that the western power crisis resulted in costs above the level the Company should have expected in the normalized power supply expense process. (Tr. 578.)

34 The Company's proposal also isolates it from the risk of variations in power supply expense during the Deferral Period. (Ex. 115 at 13: 3-7; Tr. 556.) That risk is transferred entirely to ratepayers without an offsetting risk adjustment or sharing mechanism.[6] The Commission has held that such risk adjustments are appropriate. *In the Matter of Avista Corporation*, Sixth Suppl. Order at 28, Docket No. UE-010385 (Sept. 2001); *WUTC v. Avista Corporation*, Third Suppl. Order at 52, Docket Nos. UE-991606 and 991607 (Sept. 2000).

35 Finally, the Company's proposal is one-sided. For example, the Company has included the $1.75 million cost of its Aquila Hydro Hedge. However, it has not included revenues the Company receives under that contract. (Ex. 82; Tr. 332.)

36 The Company's rebuttal to the many flaws Staff identified is meager. The Company notes that the Commission has recently allowed deferred power cost recovery for Avista and a power cost adjustment mechanism for Puget Sound Energy.[7] (Ex. 1 at 18: 16 through 19: 11.)

---

[6] In contrast, the Company proposed sharing mechanisms in Oregon and Wyoming as an incentive to control costs. (Ex. 20 at 9, last paragraph; 143-45.)

[7] *See WUTC v. Avista Corporation,* Fifth Suppl. Order, Docket No. UE-011595 (March 2002); *WUTC v. Puget Sound Energy,* Twelfth Suppl. Order, Docket No. UE-011570 (June 2002).

37 The Avista and PSE remedies are clearly distinguishable. They were adopted in general rate cases where all costs, revenues, and risk shifting were addressed. Neither Avista nor PSE had an inter-jurisdictional cost allocation controversy. PSE's power cost adjustment mechanism was adopted subsequent to the completion of a rate plan and did not reflect any costs that had been previously deferred. (Ex. 115 at 26: 1-5.)

38 Both the Avista and PSE mechanisms have a sharing feature to motivate that company to control costs. PacifiCorp has not proposed a sharing mechanism. It does not suffice to simply assert (Tr. 140, 259) that the Company has absorbed past costs.

39 In sum, the Company's proposal is a comprehensive power cost adjustment mechanism that allows PacifiCorp to defer and recover *all* variations in power supply expense with no risk for shareholders. This is clearly beyond "limited relief" intended to recover only unanticipated and extraordinary costs associated with the western power crisis. (Ex. 115 at 14: 17-19.)

B. The Company's Excess Power Costs Should Not Be Assigned to Washington Under Any Deferral Mechanism

40 As indicated above, Staff's ultimate obligation is to assist the Commission in implementing its public interest responsibilities. Staff, therefore, did not just criticize the Company's deferral proposal. It also analyzed whether

circumstances warrant deferral of power costs in Washington under any mechanism.

41 Staff concluded that the extraordinary power costs experienced by the Company during the Deferral Period were incurred to serve Utah's summer peak requirements. Thus, power cost deferrals should not be allowed in Washington in any event.

1. Utah's Summer Peak Requirements Drive the Need for Extraordinary Power Costs

42 The Company's alleged under-recovery of power supply costs during the Deferral Period arises primarily to address load requirements in the summer months. The average net power costs for July, August and September are 88% more than the average net power costs for all remaining months. (Ex. 60 at 1, col. (3), July, August, September amounts; Ex. 115 at 20: 6-24.) The variation in power costs for the non-summer months of the Deferral Period is well within expectations.

43 The issue is to identify which of the Company's jurisdictions are responsible for these high summer costs. The record demonstrates unequivocally that the Company's Eastern Control Area, particularly Utah, contributes far and away the greatest peak load requirements during the summer months of the Deferral Period. Washington load requirements do not contribute to that situation.

44 Scottish Power affirmed the impact of Utah load growth on the Company's power costs:

> Our service territories in the western US, *particularly in Utah*, are experiencing some of the highest network load growth in the country. (Emphasis added.)

(Ex. 14, Attachment at 3.) With specific regard to summer 2002, Scottish Power stated:

> [D]espite the summer months of 2002 experiencing the highest peak demand on record in Utah, our existing and newly increased generation capacity, combined with our hedge portfolio, allowed us to closely control our net power costs.

(*Id*.)

45 Most telling, however, is the evidence of retail loads detailed in Exhibits 76, 77 and 78. Staff summarized that evidence in graphs depicting monthly peak load by jurisdiction in 2001 and summer coincident peak load by jurisdiction for the 1998-2001 period. (Ex. 115 at 22-3.) These graphs are included in the Attachment. They show clearly that the peak load requirements of Utah drive the need for new summer peaking resources. In contrast, Washington's peak load occurs in the winter months. (Tr. 193-95.)

2. The Forward Summer Peaking Contracts and New Resources (Gadsby and West Valley) Exemplify the Dominance of Utah's Summer Peaking Requirements on PacifiCorp's Power Costs

46 The forward summer peaking contracts are the only extraordinary power costs during the Deferral Period that PacifiCorp attributed specifically to the

western power crisis. The evidence demonstrates that those contracts serve Utah's 2002 summer peak. The contracts cover the months July through September 2002. (Ex. 74.) Power is delivered during peak times of the day ("HLH"). (Tr. 330.) The point of delivery is through Palo Verde ("PV") into the Company's Eastern Control Area. (Tr. 331.) The peaking power received under these peaking contracts is not necessary to meet Washington's load requirements.

47 The Deferral Period also includes the operating cost of two new resources: the West Valley combustion turbine, which is a nominal 200 MW gas-fired project in West Valley, Utah near Salt Lake City, and the Gadsby combustion turbine, which is a 120 MW peaking unit near the Company's existing Gadsby Plant in Salt Lake City. (Ex. 115 at 17: 1-5.)

48 The evidence is overwhelming that these facilities were acquired to meet summer peak load requirements in the Eastern Control Area. In a March 7, 2002 press release, the Company stated that a number of new electric supply options were available through a recent Request For Proposals (RFP), including:

> A flexible lease with PacifiCorp Power Marketing, Inc. (PPM), an affiliate company, for new peaking resources in the *fast-growing Utah Power service area.* (Emphasis added.)

(Ex. 84.) The "flexible lease" is the West Valley project. (Tr. 335.)

49 The press release also states that:

> Other proposals received through the RFP are being negotiated as potential short- or long-term options to meet the area's growing energy needs. The RFP was designed to ensure impartial selection of resources available to serve *summer peaking demand in the company's Utah Power service area* . . . (Emphasis added.)

(*Id.*)

50 West Valley is operated pursuant to a lease from an affiliate of the Company. The Company filed a copy of the lease as an affiliated interest transaction. The Company reiterated in that filing that:

> The RFP focused primarily on flexible, dispatchable resources with a point of delivery in or to the *PacifiCorp's Eastern Control Area* that are capable of meeting *peak demands during the summer months 2002-04*. (Emphasis added.)

(Ex. 85 at 2.) The Company did not issue an RFP for its Western Control Area, which includes Washington. (Tr. 336.)

51 Scottish Power stated that 320 MW of new peaking capacity was commissioned at Gadsby and West Valley "further strengthening our position" given the highest peak demand on record in Utah during summer 2002. (Ex. 14, Attachment at 3.)

52 PacifiCorp studied the impact of Gadsby and West Valley on its results of operations from 2003-2006. (Ex. 80.) The study includes the cost of wheeling from "SP-15 to Mona" that is avoided by the addition of Gadsby and West Valley. (Ex. 62 at 7: 12-14; Ex. 80, Attachment at 1, "Transmission Savings".) SP-15 is located in southern California. Mona is located in central Utah. (Tr. 304.)

53 The average cost of energy that is avoided by the addition of Gadsby and West Valley for delivery into Utah is significantly more expensive than power delivered into Washington for any of Washington's summer requirements that are not met with regional resources.[8] (Tr. 585-86.) The addition of wheeling charges to deliver power into Utah exacerbates the price differential for alternative power and further undermines any claimed benefits for Washington.

54 Finally, Exhibit 86C includes the Company's presentations to its Board of Directors, beginning September 4, 2001, regarding the Gadsby and West Valley projects. The document states clearly that Gadsby and West Valley were acquired to meet the "Utah bubble" each summer given transmission constraints that necessitate investment in peaking resources within Utah. (Tr. 566 and 569-71.) The exhibit is packed with discussions that the benefits of Gadsby and West Valley are local to Utah. Attention is drawn specifically to the following pages of the October 12, 2001 presentation: Page 2, Executive Summary; Page 3, Executive Summary; Pages 3-4, "Wasatch Front" section; and Page 13, Investment Risk Discussion. Washington is not mentioned in the exhibit.

55 Thus, the evidence is abundant and clear that the West Valley and Gadsby projects were added only to serve summer load in Utah. PacifiCorp attempts to deflect attention from this evidence by alleging several benefits of the projects for

[8] The average cost of energy is determined from Exhibit 80C by dividing "Market value while on

Washington. (Ex. 62 at 7: 5-21.) The Company was asked to document each of these benefits, but it could provide no specific studies or analyses. The information that was provided addressed only the Company's Eastern Control Area or total system benefits. (Ex. 87, *e.g.*, Response at "(A) Reserves".)

C. The Company's Proposal for a 60-90 Day Prudence Review of Deferred Amounts Should Be Rejected

56 The Company recognizes that the ultimate amount of deferrals, if granted, is currently unknown. (Ex. 83.) Nevertheless, the Company proposes immediately to defer and recover its excess power costs.

57 Recognizing this obvious deficiency, the Company on rebuttal proposed a 60-90 day period after the Deferral Period to audit and adjust the deferred amounts when they are known. (Ex. 8 at 19 : 17 through 20: 2 ; Ex. 62 at 2: 5-14.) This review would not, however, change the proposal to begin immediate recovery of deferred amounts. (Tr. 322.)

58 The Commission should reject this late effort. The record is clear that the forward summer peaking contracts are the only costs that relate to the western power crisis and occurred during the Deferral Period. Those contracts serve summer peak load in Utah. They do not provide benefits to Washington.

---

line" by "Generation." (Tr. 303.)

59 The costs of Gadsby and West Valley were also incurred to serve Utah's summer peak. All other costs were incurred prior to the Deferral Period or are unrelated to the power crisis.

60 In essence, a substantial record exists to deny *any* mechanism that would allow PacifiCorp to defer excess power costs. The Company's 60-90 day review process ignores the weight of that evidence. The Commission should not do the same.

D. Conclusion on Deferred Accounting

61 In analyzing the Company's proposal to defer excess net power costs, Staff assumed that the Rate Plan Stipulation never existed. Staff also assumed that the costs of the forward summer peaking contracts were incurred prudently for the system, were extraordinary, and were related to the western power crisis of 2000-2001. These were the only such costs the Company identified for the Deferral Period.

62 Nevertheless, Staff identified critical flaws in the deferral mechanism proposed by PacifiCorp. Staff also demonstrated that Washington should not be assigned the cost of the forward summer peaking contracts or the cost of new resource additions in the Eastern Control Area. Therefore, Staff recommends that the Commission deny deferred accounting for PacifiCorp in any shape or form.

63 This would not be a result that the Company should find unfair, unexpected, or unusual. When FERC implemented price caps in 2001, it was responding to requests for that exact remedy. One party requesting price caps was PacifiCorp. (Ex. 18 at 34.) Therefore, when the Company in 2001 entered the forward summer peaking contracts, it did so with full knowledge that price caps could be implemented.

64 The Company agreed in Wyoming not seek recovery of the forward summer peaking contracts. (Tr. 322-23.) It was recently denied recovery of excess power costs in a recent decision of the Wyoming Public Service Commission. (Ex. 17, ¶¶143-208.) An Administrative Law Judge at FERC recently dismissed with prejudice Company complaints seeking to modify or abrogate the forward summer peaking contracts. (Ex. 18.)

65 The Company also agreed in a settlement in Utah that it would not seek to recover excess power costs in that state. (Ex. 18 at 15; Tr. 322-23.) That is an amazing commitment given that Utah is the primary beneficiary of those costs, which PacifiCorp now seeks to recover from Washington customers who receive no benefit whatsoever.

III.

THE MODIFIED ACCORD COST ALLOCATION METHOD SHOULD BE REJECTED AS A BASIS FOR RATE RELIEF

66 The Company characterizes its case as a request for "limited relief" under the *PNB* standards. (Ex. 1 at 7: 9-19; Ex. 8 at 2: 7-11.) That request is based entirely upon a presentation of Washington stand-alone financial results that assumes the Modified Accord inter-jurisdictional cost allocation methodology (Modified Accord).

67 Staff recommends that the Commission reject the Company's presentation. Modified Accord has not been accepted by the Commission or by Staff for ratemaking purposes. Modified Accord also allocates an unfair share of the cost of new generation to states, like Washington, which do not have load growth that necessitates those resources.

A. Historical Background

68 A brief history provides context for the cost allocation dispute. That history shows that the Utah Commission's unilateral decision to adopt rolled-in pricing: (1) causes the Company's cost recovery short-fall; and (2) renders Modified Accord obsolete. (Tr. 449.) Thus, there would be no inequity if rate relief is denied in Washington.

1. The Merger of Pacific Power & Light and Utah Power & Light

69 In 1987, Pacific Power & Light filed an application in Cause No. U-87-1338-AT to acquire the assets of Utah Power & Light to create PacifiCorp. The case raised issues related to the integration of Pacific's low cost hydro-based

system with Utah's high cost thermal-based system, and issues related to cost allocation for a utility with two operating divisions with diverse cost structures. (Ex. 110 at 4.) The Commission approved the transaction, but it expressed clearly its concerns about these issues:

> The Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes the integration of the power supply function for the two companies should be done in a manner consistent with Pacific's least-cost planning process, now getting underway. In the meantime, the Commission views Pacific's current average system costs as the appropriate basis for rates.

Docket No. U-87-1338-AT, Second Supplemental Order Approving Merger With Requirements at 14 (July 1988). In order to alleviate the Commission's concerns, Pacific's policy witness (Mr. Reed) addressed the allocation issue. He stated:

> Pacific will initiate action soon to reconvene the jurisdictional allocation committee within six weeks after the final approval of the merger, and that committee is the appropriate forum for resolving the allocation issue, including allocation of power supply costs and benefits.

(Ex. 110 at 5, citing Ex. T-43 at 1: 16-20 from Cause No. U-87-1338-AT.) This commitment also addressed PacifiCorp's assurance that Washington would receive its fair share of merger benefits. (Ex. 110 at 5.)

70 Mr. Reed also sought to allay concerns regarding increased regulatory burdens. He stated that "the merger will not significantly increase the regulatory burden of the state and federal regulatory commissions." (*Id*.)

71 He also stated that Washington ratepayers would be held harmless if Utah were to adopt rolled-in cost allocations:

> But I will hasten to add that through the allocation process we will insure and I'm sure you will insure that there's no cross-subsidization whereby a Washington customer or any Pacific Power and Light customer is helping to subsidize that price reduction. If there is a subsidy required, it's going to be a subsidy by the shareholder.

(Ex. 110 at 6, citing Tr. 733 from Cause No. U-87-1338-AT.)

72 Despite Mr. Reed's assurances, Utah has acquired a disproportionate share of merger benefits. (Tr. 471.) An equitable sharing of those benefits would be evident if the relative rates in all jurisdictions exhibited a similar pattern over time. However, since the merger in 1989 to 2000, there has been a significant decrease in residential, commercial and industrial rates in Utah. That same pattern did not occur in the other states. This also suggests that those other states are making up for lost revenues from the Company's Utah operations. (Ex. 110 at 6-8 and Attachment.)

2. PacifiCorp Inter-Jurisdictional Task Force on Allocations (PITA)

73 Following the acquisition, PacifiCorp convened representatives from the Company and from the jurisdictions it serves to study inter-jurisdictional cost allocation issues. The group became the PacifiCorp Inter-jurisdictional Task Force on Allocations or "PITA." (Ex. 125 at 3: 19-23.)

74 The purpose of PITA was to create an allocation method that was fair and based on cost causation. This meant that the lower cost Pacific division, which included Washington, should not receive overall cost increases as a result of acquiring the higher cost Utah division. It also meant that the benefits from the consolidation should be fairly and reasonably shared among all PacifiCorp jurisdictions. Jurisdictions were also to assume responsibility for *direct costs* each particular jurisdiction imposed on the system, and for those total system costs that could not be directly assigned. (Ex. 125 at 3: 24 through 6: 7.)

75 PITA developed several cost allocation methods, including the "Consensus Method," the "PITA Accord Method," and, finally, Modified Accord. Modified Accord has been used by the Company in its regulatory filings in all states, except Utah. (Ex. 8 at 11: 19-20.)

76 Throughout PITA, Washington advocated that all cost allocation methods must reflect the low cost hydro portfolio of the Pacific division. (Ex. 125 at 5: 13-16.) PITA disbanded in April 2000 as a result of the Utah rolled-in cost allocation decision. (Ex. 125 at 5: 21-23.)

3. The Utah Decision to Adopt "Rolled-In" Cost Allocations

77 In 1998, in a unilateral decision, the Utah Public Service Commission adopted a "Rolled-In" allocation method that allocates common costs, including power costs, to all jurisdictions. That decision allowed Utah to capture the

benefits of the low cost Pacific division for Utah customers. As Utah's load growth continues, Utah captures ever-increasing amounts of the low cost Pacific system. (Ex. 101 at 19: 18 through 20: 4; Tr. 471.))

78 The Utah decision also shifts increasing amounts of Utah's high cost thermal resources to other jurisdictions, such as Washington, that have more modest load growth. If other jurisdictions do not raise rates, the Company is unable to recover its cost of service across all its jurisdictions. (Ex. 8 at 16 : 19-20; Ex. 101 at 20: 5-12.) The "Allocation Shortfall" that results from Utah's rolled-in decision was $38 million in 2002. The same amount is estimated for 2003. (Ex. 32.)

4. The 1999 Rate Case

79 PacifiCorp filed a general rate case in 1999 in Docket No. UE-991832. This was PacifiCorp's first opportunity since the acquisition of the Utah properties to prove that Modified Accord produces fair results in Washington and holds Washington's customers harmless from the 1989 merger**.**

80 However, the Rate Plan Stipulation was entered that provided the Company rate relief over the initial three years of a five-year period. These increases were not based on Modified Accord. (Tr. 175.) The Stipulation, in fact, was intended to allow the Company to solve its cost allocation difficulties. (Ex. 101 at 11: 9-12.)

5. The Structural Realignment Proposal

81 In 2000, the Company developed the "Structural Realignment Proposal" (SRP) – a comprehensive restructuring of PacifiCorp into six separate electric companies, a generation company and a service company.

82 The SRP was designed to address the Company's concern that existing mechanisms for inter-jurisdictional allocations are "clearly broken". (Tr. 196 and 463-64.) The "gridlock" over inter-jurisdictional allocations continued to result in the Company suffering an earnings shortfall. (Tr. 195; Ex. 125 at 13: 2-6.)

83 The SRP was filed with this Commission on December 1, 2000 in Docket No. UE-001878. The Company did not propose Modified Accord in the SRP. It used a different cost allocation method called "Fair Share". (Tr. 464 and 593.)

84 The SRP was withdrawn voluntarily by PacifiCorp in 2002 so that the Company could pursue the current multi-state process (MSP). (Ex. 125 at 6: 7-10; Tr. 532.)

6. The Multi-State Process

85 In 2002, the Company initiated the Multi-State Process in an attempt to solve cost allocations through a consensus approach among all states. The Company proposed initially to finalize the MSP in September 2002, but the MSP continues today. (Ex. 110 at 1-3.) Washington has been an active participant in the MSP.

86 The MSP participants are studying various cost allocation alternatives. No agreement or impasse has been reached. It is premature to draw any conclusions about the outcome of the MSP. (Ex. 125 at 13: 8-20.) However, no party in the MSP is advocating any of the allocation methods used during PITA, including Modified Accord. (Ex. 125 at 11: 21-25.)

B. It is Unreasonable to Use Modified Accord to Assign the Cost of New Resources to Washington

87 As shown in the prior section, Modified Accord has not been accepted by this Commission or Staff for ratemaking purposes. (Ex. 125 at 3: 6-8 and 11: 19-21; Ex. 128.) Utah's unilateral decision to adopt rolled-in pricing also meant the demise of Modified Accord for purposes of inter-jurisdictional cost allocation .

88 Modified Accord is also flawed because it allocates system-wide the cost of new generation that was built to serve significant load growth in Utah. As a result, states, such as Washington, with load growth that does not require new resources, are allocated a disproportionate share of the cost of those resources. (Ex. 125 at 3: 3-5 and 8: 24 through 9: 3; Tr. 457.)

89 Exhibit 127 demonstrates this phenomenon. Under Modified Accord, a "System Generation" factor is calculated.[9] Utah's System Generation factor would allocate only 38% of the cost of the new Gadsby and West Valley resources, even though those resources were acquired to serve growth in Utah's

summer peak. Washington, on the other hand, would be allocated 9% of the cost of those new peaking resources, even though the Company has not proven any benefits from those projects for Washington. (Ex. 125 at 10: 21 through 11: 1.)

90 In fact, Modified Accord allocates the cost of new resources to Washington even though Washington's load decreased slightly from 1998-2001, while Utah's retail load increased significantly from 37% to 57% of the Company's system. (Ex. 9 at 1.) The Company's July firm peak in Washington decreased from 37% to 27% of the system from 1998-2001. In contrast, Utah's July firm peak increased from 50% to 78% of the system. (Ex. 9 at 3.) Peak loads, as measured by the sum of the twelve coincident peaks for each month, grew 60% in Utah, but only 18% in Washington. The system peak load was 22%. (Ex. 126 at 2.)

91 These trends continued in 2002. Washington's load decreased 75,000 MWh from 1998 to 2002. Utah's loads were 3 million MWh higher over the same period. (Tr. 173 and 189.)

92 Modified Accord also violates the *principle* that each jurisdiction should be held responsible for the direct costs it imposes on the system. (Ex. 125 at 4: 4-6; Tr. 609 and 611.) It inappropriately allocates to the system the cost of special contracts with industrial customers that state commissions approve for purely

---

[9] The specific calculation is explained in Exhibit 125 on page 7.

local purposes. It also inappropriately allocates to the system the cost of state taxes. (Ex. 125 at 9: 12-18.)

93 Thus, Staff recommends that the Commission reject the Company's presentation of Washington stand-alone financial results. It relies upon an unaccepted and unacceptable Modified Accord cost allocation method.

94 The Company's rebuttal to this recommendation is without merit. First, the Company offers Exhibit 9 for the proposition that Modified Accord does not over-assign the cost of new resources to Washington because Washington's loads have grown faster than the system average. (Ex. 8: 18-20.)

95 The argument misses the point, however. Washington should not be assigned the cost of new resources under *any* allocation methodology until benefits of those resources have been shown for Washington customers. The Company has not made that case. The evidence of Utah load growth demonstrates that it is not possible to do so.

96 The Company argues that the stand-alone financial results for Washington do not change if alternative cost allocation methodologies are used. (Ex. 8 at 8: 15 through 10: 22.) Thus, under any cost allocation method, Washington's financial results are poor and deteriorating.

97 Discussions ongoing in the Multi-State Process, however, contradict that argument. Various cost allocation methodologies are being studied in the MSP.

They include methods that allocate costs according to "control areas" and methods that directly assign costs by state.[10] (Tr. 201-04.) Even within these general categories of allocation methods, various assumptions have been tested which alter the results. [11] (Tr. 203-04.)

98 The MSP studies demonstrate that Washington financial results, in fact, do change and, in some cases, change materially, if alternative cost allocation methodologies are applied. (Exs. 28 and 29.) Using a direct assignment approach, Washington's revenue requirement would actually *decrease* 11% in 2003 compared to Modified Accord.[12] (Ex. 29, Attachment, Study 52.3; Tr. 202.)

99 The Company claims that Staff has been able to determine whether PacifiCorp's rates continue to be just and reasonable using the periodic reports filed by the Company. (Ex. 8 at 12: 1-9; Ex. 46 ; Tr. 276.) The claim has no basis in fact. The Company's periodic reports have been tardy (Tr. 208) and they have failed to comply with Commission rule. (Ex. 34.) The reports are also based on Modified Accord, which has not been accepted for ratemaking purposes.

---

[10] A control area is an electrical system bounded by interconnection, metering and telemetry. It controls generation directly to maintain its interchange schedule with other control areas and it contributes to frequency regulation of the interconnection. (Ex. 125 at 13: 15-18.)

[11] These include changes in assumptions for load forecasts, hydro re-licensing, clean air initiatives and carbon tax costs. (Ex. 28, Attachment; Tr. 203-04.)

[12] The Company argued that this particular study was meaningless because it is based upon a 1999 load forecast. (Tr. 264.) However, the negative revenue requirement for Washington would not change materially with an updated load forecast since the results for all states would be impacted proportionately. (Tr. 539.) In fact, given the disproportionate load growth between Utah and Washington, a direct assignment methodology would further decrease Washington's revenue requirement using an updated load forecast.

100 Moreover, the Commission recognized expressly that the Post Rate Plan Earnings review is *the* appropriate time to determine whether the Company's rates remain just and reasonable. The Rate Plan Stipulation states:

> [The Post Rate Plan Earnings Review] will enable the Commission and the Parties to examine the Company's performance over the Rate Plan Period, and to evaluate the reasonableness of the Company's rates in light of the conditions that exist following the Rate Plan Period.

(Ex. 2 at Section 1(b).)

101 Thus, Staff reviews *this* Company's periodic reports only for compliance with Commission rules. (Tr. 596-97.) Staff does not use, cannot use, and should not use the reports to assess PacifiCorp's financial performance. (Ex. 34.)

102 The Company states that Staff was able to agree that the Rate Plan Stipulation produces just and reasonable rates for the five-year period even though Staff was faced with an unresolved cost allocation issue. Therefore, the Company argues, Staff should be able to work through that problem here. (Ex. 8 at 9: 3-8.)

103 The argument assumes that Staff had to rely upon a specific cost allocation methodology in order to enter the Rate Plan Stipulation. However, as Staff explained, the Rate Plan Stipulation was a "black box" settlement in which Staff did *not* rely upon any specific element of a revenue requirement determination, including cost allocation and all other potential ratemaking adjustments. (Tr. 453 and 550.)

104 Staff did consider the magnitude of the revenue increase requested by the Company in the 1999 Rate Case and the resulting rate impacts that could result from an alternative cost allocation method, as well as other elements that affect revenue requirements. In addition, Staff considered the Rate Plan's timing and level of rate increases, and the impact of the Centralia and Scottish Power merger credits, in order to provide rate predictability during the Rate Plan period. (Exs. 35 and 37.)

105 Staff also took into account that the Company's Transition Plan made it difficult to set rates during the five-year Rate Plan period. (Tr. 516.) The Company also recognized that difficulty. It stated during presentation of the Rate Plan Stipulation that:

> It is difficult to set rates during the implementation of the Transition Period because the expenditures that must be made in the early years of the transition are "lumpy, " and it is therefore challenging to identify a representative test period upon which to set rates.

(Ex. 12.)

106 The Commission itself acknowledged this same problem, which the Rate Plan Stipulation solved by providing stable prices to consumers, a steady stream of revenues to the Company, and a mechanism for measuring performance of the Company after the Rate Plan was over:

> The Parties agree that the rate plan offered in the Stipulation is in the public interest and will provide rates for the Company that are just, fair reasonable and sufficient throughout the Rate

> Plan Period….The rate plan recognizes the difficulty of setting rates during this transitional period, and provides the Company with an opportunity to earn reasonable returns, on balance, over the Rate Plan Period . . .

(Ex. 2 at Section 1(b).)

107 Thus, based on all of these factors, Staff was able to conclude that the Rate Plan produced just and reasonable rates over the 5-year period. It did not assume any specific cost allocation method, nor was it necessary to do so.

108 Finally, the Company argues that Staff's position condemns the Company to "cost allocation purgatory" in which there can be no consideration of PacifiCorp's financial condition. (Ex. 8 at 1: 9-12 and 11: 7-11.) The Company ignores Staff's effective response to this exact criticism. Staff testified that rate relief, if justified, would be available even absent resolution of cost allocations:

> The Company would need to present its total financial profile. This presentation would show that the entire company is facing a financial emergency, that interim relief is sought in Oregon and Utah, and that some amount of relief should be apportioned to Washington. Even though there is not an accepted allocation methodology, this would go a long way to complying with the requirements of Section 11 despite the current controversy over allocations.

(Ex. 101 at 11: 16 through 12: 2.)

109 Staff elaborated on this testimony in a response to a Company data request:

> The filing of [total company financial results] would not solve the allocation issue. The filing of this information would meet the requirements of Section 11 if used to support similar contemporaneous

> interim requests in both Utah and Oregon. Furthermore, the Commission would understand the nature of the emergency and its impact on the Company's utility operations in Washington, and it would determine the amount of interim relief necessary in the context of the PNB standards. Finally, any interim amount granted would be subject to refund and a resolution of allocation issues at the conclusion of the general rate case.

(Ex. 36, part b.)

110 Thus, while this may not be heaven, it certainly is not purgatory. The Staff recommendation allows the Company to receive rate relief without resolving the cost allocation issue.[13] (Tr. 473-75, 482-83 and 497.)

IV.

THE COMPANY HAS OTHERWISE FAILED TO DEMONSTRATE THAT "LIMITED RELIEF" IS WARRANTED UNDER THE *PNB* STANDARDS

111 In the prior section, Staff demonstrated that the Company should be denied rate relief because the alleged basis for relief is a meaningless presentation of Washington stand-alone financial results that relies upon Modified Accord. In this section, we demonstrate additional short-comings that render that same presentation irrelevant.

112 PacifiCorp states that it is entitled to "limited relief" under the *PNB* standards. The Company alone bears the burden to prove that such standards have been met. RCW 80.04.130. (Tr. 487-89.) The Company did not, however,

[13] For example, the extraordinary costs of an earthquake that should be allocated to Washington might be allocated on the basis of rate base. Extraordinary costs related to a severe power crisis might be allocated on the basis of energy or revenues. (Tr. 483.)

present evidence of total company operations and the financial circumstances it faces. It did not demonstrate the impact of "limited relief" on its total financial condition. It did not demonstrate how "limited relief" will alleviate a Company financial crisis.

113 Instead, the Company relied exclusively on a presentation of Washington financial results *as if* Washington is a "stand-alone" utility. It then draws from that hypothetical the conclusion that financial results in Washington are inadequate and deteriorating, thus, necessitating the rate relief it requests. (Ex. 1 at 9-16; Exs. 3C through 7; Exs. 50C through 56C.)

114 The Company's presentation, however, is irrelevant because the Company finances its operations on a total-Company basis, not on a Washington-only basis. Its rate of return (if one existed)[14] and its other financial parameters (such as coverage ratios) are established on a total-Company basis. On a total-Company basis, PacifiCorp does not even come close to meeting the *PNB* test for emergency rate relief.

A. Introduction: The *PNB* Standards

115 The *PNB* standards require *severe* and *imminent* jeopardy that threatens a company's access to capital on reasonable terms. Thus, without emergency rate

[14] Neither the Rate Plan Stipulation nor the Commission's Order approving the Stipulation established an authorized rate of return for PacifiCorp. (Tr. 160-61.)

relief, a company's ability to satisfy its public service obligations to both ratepayers and shareholders is imperiled.

116 The *PNB* test consists of the following specific standards:

1. This Commission has the authority, in proper circumstances, to grant interim relief to a regulated utility; this should be done only after an opportunity for adequate hearing.

2. An interim increase is an extraordinary remedy, and should be granted only where an actual emergency exists or where relief is necessary to prevent gross hardship or gross inequity.

3. The mere failure of a utility's currently-realized rate of return to equal the rate of return previously authorized to the utility by this Commission as adequate is not sufficient, standing alone, to justify a grant of interim relief.

4. The Commission should review all financial indices as they concern the applicant, including the rate of return, interest coverage, earnings coverage, and the growth, stability, or deterioration of each, together with the immediate and short-term demands for new financing and whether the grant or denial of interim relief will have such an adverse effect on financing demands as to substantially affect the public interest.

5. In the current economic climate the financial health of a utility may decline very swiftly, and the interim relief stands as a useful tool in an appropriate case to stave off impending disaster. However, this tool must be used with caution, and it must be applied only in cases where the denial of interim relief would cause clear jeopardy and detriment to its ratepayers and its stockholders. This is not to say that interim relief should be granted only after disaster has struck or is imminent, but neither should interim relief be granted in any case where full hearing can be accomplished and the case in chief resolved without clear jeopardy to the utility.

6. As in all matters before this Commission, we must reach our conclusion while keeping in mind the statutory charge to this

> Commission that we must "regulate in the public interest." This is our ultimate responsibility, and a reasoned judgment must give appropriate weight to all relevant factors.

WUTC v. Pacific Northwest Bell Telephone Co., Second Suppl. Order at 13, Cause No. U-72-30 tr (1972) (*PNB Order*.)

117 Interim rate relief is designed only to address an *immediate* emergency need for additional revenue. The Commission:

> [W]ill not consider or give weight to long-range economic projections but will concern itself only with an analysis of existing and actual conditions and short-range projections, which in the main are least subject to volatile economic winds and are more conducive to credible reliability than long-range plans…[I]nterim rate relief should be granted only upon a reasonable showing that an emergent condition exists and that without affirmative relief the financial integrity and ability of the company to continue to obtain financing at reasonable costs will be compromised and placed in jeopardy. The decision must be made solely upon the record and within the time frame that has close proximity to the claimed emergent conditions.

WUTC v. The Washington Water Power Company, Second Suppl. Order, Cause No. U-80-13 (1980). *See also, WUTC v. Cascade Natural Gas Corp.,* Second Suppl. Order, Cause No. U-74-20 (1974); *WUTC v. Puget Sound Power & Light Co.,* Second Suppl. Order, Cause No. U-80-10 (1980).

118 The Commission recently affirmed that a company seeking emergency rate relief must show a clear and present extraordinary need, with severe financial consequences, beyond the need for general rate relief. It applied this standard to deny emergency rate relief to Puget Sound Energy. *WUTC v. Puget*

Sound Energy, Inc., Sixth and Seventh Suppl. Orders, Docket Nos. UE-011163 and 011170 (2001). Significant to the case at hand, PSE claimed detrimental impacts of the western power crisis. Its proposed form of relief, which the Commission rejected, was to defer and recover power costs.

119 The Commission also has stated that it would consider whether a company was taking extraordinary steps to preserve its financial integrity, including the reduction of management salaries, and the deferral of substantial expenses and capital investment. Also relevant is whether a company would lose access to capital markets without relief when the need for financing was clear and immediate, especially for specific major projects that cannot be completed absent current financing. *In re Avista Corp. Request for Recovery of Power Costs Through a Deferral Mechanism,* Sixth Suppl. Order, Docket No. UE-010395 (Sept. 2001). The Commission considered these factors in denying PSE extraordinary rate relief in Docket Nos. UE-011163 and UE-011170, *supra*. These factors were also addressed in the seminal *PNB Order* at page 4.

B. The Company Cannot Justify Rate Relief Under the *PNB* Test

120 The Company's understanding of the *PNB* standards is identical to that described above (Ex. 8 at 5: 18-19; Exs. 11 and 31.) The Company also was candid in agreeing that those standards have not been met. (Tr. 171.)

121 The Company agreed that its overall financial condition is "significantly improving" and that it is not in financial distress on a total-Company basis. (Tr. 156, 158 and 175.) It could provide no evidence of poor financial indicators on a total-Company basis. (Ex. 32; Tr. 155-56.) It could provide no evidence that increased power costs place it in financial distress. (Tr. 190.)

122 PacifiCorp admitted that it finances its operation on a total-Company basis. (Ex. 16.) It has an "A" credit rating that allows the Company to access the capital markets on reasonable terms in order to fulfill its public service obligations. (Tr. 163; Ex. 79.) That access will not be impaired absent rate relief. (Tr. 165.)

123 In fact, Scottish Power has recently authorized PacifiCorp to issue new common stock. (Ex. 18 at 14.) The Company stated in its most recent 10-K report to the Securities and Exchange Commission that it has currently available committed bank revolving credit agreements in the amount of $625 million at a cost around 2.2%. (Ex. 45; Tr. 193.) It also stated that:

> [I]ts existing and available capital resources and the new revolving credit agreements will be sufficient to meet working capital, dividend and construction needs in 2003.

(*Id.)* The Company was not aware of any internal analysis, study or report, or any presentation to the financial community, that demonstrated an inability to access capital to meet future needs. (Ex. 15.)

124 The Company did not demonstrate that its future cash needs are necessary and essential and, thus, cannot be delayed. In fact, just the opposite is true. The Company has budgeted over $300 million in capital expenditures for information technology through 2006. (Ex. 55C.) It does not plan to defer any of that amount, nor has it explained why it cannot do so. (Ex. 101 at 13: 15-18.)

125 PacifiCorp does have future cash needs to fund new distribution facilities, but that need is modest in Washington and can be funded with current Washington cash flows. (Ex. 55C; Tr. 492.) The primary need for cash to fund new distribution is in Utah. (Ex. 56C ; Ex. 101 at 15: 7-9.) Because Utah's load growth far outpaces Washington's, the Company's cash requirements for new generation and transmission also are driven by Utah. (Ex. 101 at 15: 13-19; Exs. 126 and 127.)

126 The Company did not demonstrate that it has taken steps to preserve its financial integrity. It could not identify a single capital project or significant expense that was being deferred. (Tr. 146.) It has no plans to reduce management salaries, lay off unnecessary employees, or suspend new hiring. (Tr. 145.)

127 Other evidence demonstrated that PacifiCorp is hardly a company facing an imminent and severe financial emergency that requires rate relief of any amount or in any form. PacifiCorp reported operating profits of $221 million for

the quarter ended September 30, 2002, compared to an operating loss of $101 million for the prior year period. (Ex. 13.) With respect to future profits, Scottish Power stated that:

> We are firmly on track to achieve the targets we have set, particularly for PacifiCorp, where we are aiming to double operating profit to $1 billion over the next three years.

(*Id*.)

128 PacifiCorp remains poised to achieve this profit target. (Ex. 27 at 4.) A "key driver" in meeting that target is the Transition Plan. The Plan "remains on track" and has already accumulated benefits of $164 million out of a goal of $300 million. (Ex. 14 at 3.) PacifiCorp is already two-thirds of the way toward achieving its savings target for fiscal year 2003. (Ex. 10.)

129 In sum, there is no evidence that PacifiCorp faces an immediate and severe emergency that jeopardizes its ability to obtain necessary financing. To the contrary, the evidence is clear and convincing that PacifiCorp is on solid financial ground for the near-term.[15]

---

[15] The Company produced forecasts of its Washington stand-alone financial results and cash requirements for the period 2004-2006. (Exs. 3C-7.) Even if Washington stand-alone results were relevant (which they are not), these forecasts are still irrelevant. As discussed in Section V, A, *supra*, the Commission examines only existing and actual conditions and short-range forecasts in determining whether there is a need for emergency rate relief. Information beyond 2003 is not germane to that examination.

Even if the Commission considered the projections, it should find them of little, if any, value. They are not based upon a test year analysis with known and measurable changes. (Tr. 289-90.) The Company admitted that its projections are not "rate case quality." (*Id*.)

130 PacifiCorp does not dispute this conclusion. Instead, it argues that it is necessary to look at Washington stand-alone results in order to prevent cross-subsidies and to avoid obscuring the results in one state by the results from other states. (Ex. 8 at 7: 12-20.) However, those comparisons cannot be made since Washington's costs on a stand-alone basis would be "very different" from what even Modified Accord produces for Washington as part of a multi-state utility. (Tr. 279.) Even if it were relevant to look at Washington stand-alone results, the Company earned a 7% return in Washington for 2002. (Tr. 279.) That does not indicate stand-alone operations that require rate relief to avoid "gross hardship or inequity."

131 The Company's argument is also inconsistent with the position it took recently in its interim rate filing in Utah. There, it offered the testimony of its chief financial officer regarding total-Company operations. (Ex. 36, Attachment.)

132 The argument is also inconsistent with the Company's position when the Rate Plan Stipulation was presented to the Commission for approval on July 17, 2000. A panel of witnesses consisting of Staff, the Company and Public Counsel was asked whether Section 11 of the Stipulation contemplated interim rate relief if "electric or credit markets going haywire" prevented the Company from achieving sound financial health. Staff summarized the requirements for interim relief as follows:

MR. ELGIN: Yes. I would just clarify that. It's not just the energy market. It's primarily that the Company needs access to capital. It has a certain public service obligation, and that it's earnings and tests in order to access credit is such that without interim rate relief, it can't access credit and that it would have a material impact on the public future service . . . So it's a very strict standard in the context of the company's ability to access capital and provide reasonable service to the public.

JUDGE MOSS: So we would expect to see experts from the capital market sector come to testify that this company is not going to get any access to credit under the current circumstances?

MR. ELGIN: You would see primarily the company's chief financial officer presenting testimony and exhibits showing that the company's coverages were such that it would not be able to access and sell any debt is the testimony and analysis you would see.

JUDGE MOSS: Let me round that question out in this fashion, and I appreciate the answer. Let's hypothesize a situation such as we experienced recently in the Pacific Northwest where we have had some rather significant spikes in the wholesale price of electricity. Is that the kind of thing that would trigger this, or is that conceivable?

MR. ELGIN: Probably not. If it would be that that spike were to occur and it would be such that it was an extended period of time that we were perceiving those kind of energy prices, and the company had to access those markets on a regular basis for a significant portion of its power supply, it might, but I suspect for this particular company, it would not.

(Ex. 44 at 867-869.) Public Counsel concurred with Staff's interpretation (Ex. 44 at 869), as did counsel for the Industrial Customers of Northwest Utilities. (Ex. 44 at 932.) The Company's witness was silent. She did not contest the interpretation of all other parties. (Tr. 164.)

133 PacifiCorp's argument that Washington stand-alone results should be the focus is also inconsistent with reality since Washington stand-alone operations, however measured, are not the basis upon which the Company finances. Indeed, the Commission in *PNB* expressly noted the importance of examining the *total* financial circumstances facing a company seeking interim rate relief. In denying interim relief, the Commission stated:

> The record demonstrates that the company does not contemplate any permanent financing for approximately another year. In the interim capital requirements are projected to be met from short term borrowing at or below rates applicable to prime borrowers.

PNB Order at 4. These factors were critical to the conclusion that PNB's fundamental responsibility to carry out its public service obligations was not imperiled absent interim relief and that such relief was unnecessary to avoid gross inequity and hardship. The same conclusions are automatic for PacifiCorp.

134 The Company drew attention to the following language at page 4 of the *PNB* order:

> While rate of return figures on common equity of necessity are for the company as a whole, there is no demonstration in the record that Washington intrastate operations are failing to contribute their proportionate share to overall earnings.

(Tr. 477-78.) That passage, however, assumes that costs have been allocated among the states using a fair and appropriate method. No such cost allocation method exists today for PacifiCorp. Thus, there is no way to conclude that Washington, or any other state, is not contributing its "proportionate share to overall earnings." It is just as likely that Washington is subsidizing other states.

135 Finally, the Company argues that Washington customers have benefited from rate relief provided in other jurisdictions by improving the Company's current financial condition and by subsidizing Washington's share of costs attributable to the western power crisis. (Ex. 1 at 16: 14 through 18: 12; Ex. 8 at 19: 1-5; Ex. 16.) In this regard, the Company alleges $98 million in higher power costs in Washington that shareholders have borne. (Ex. 8 at 6: 10-14 Tr. 140 and 259.)

136 Purely as a factual matter, it is misleading to cite rate relief in Utah as a premise to argue that Washington has not paid its fair share of higher power costs. $17 million in general rate relief and $40 million in interim rate relief was granted in Utah, but only after the Utah Commission's decision to adopt "rolled-in" pricing first reduced rates in Utah by $85 million. That decision had a significant impact on the Company's financial performance, which general and interim rate relief in Utah only partially restored. (Ex. 101 at 19: 15 through 21: 18.) The impact of Utah's rolled-in decision on PacifiCorp's financial performance will continue well into the future, absent a consensus resolution in the MSP. (Ex. 32, "Allocation Shortfall".)

137 More important than factual oversights, however, relief granted in other states does not mean that Washington has not contributed its fair share. Other states set rates in accordance with ratemaking policies that are not necessarily

consistent with the ratemaking policies of this Commission. They relied upon different and earlier test periods for measuring revenues, costs and rate base. Thus, rate relief in other jurisdictions is not indicative of an under-recovery of costs in Washington. (Ex. 101 at 16: 11 through 17: 2; Ex. 104.)

V.

THE COMPANY'S PROPOSAL VIOLATES THE RATE PLAN STIPULATION

138 The preceding sections demonstrate that the Company's proposal to defer and recover "excess net power costs" should be rejected even in the absence of a Rate Plan because:

- The proposed deferral mechanism is flawed
- Washington should not be allocated excess power costs under any deferral mechanism
- PacifiCorp is not entitled to rate relief under the *PNB* standards.

139 The Company's proposal also violates the Rate Plan Stipulation in several important ways. To the extent the Rate Plan Stipulation is ambiguous, it should be construed most strongly against the party that drafted it. *Wilkins v. Grays Harbor Community Hospital,* 71 Wn.2d 178, 184, 427 P.2d 716 (1967). That party is PacifiCorp. (Tr. 531-32.)

A. Centralia and Merger Credits (Ex. 2 at Sections 2 and 4.)

140 The Rate Plan Stipulation states clearly that changes in the Company's general base rates are limited to 3% increases on January 1, 2001 and January 1, 2002, and a 1% increase on January 1, 2003. These increases are exclusive of the Centralia credit and the Merger credit. According to the Stipulation:

> The amount of the *merger credit* is $3 million per year, or approximately 1.7%, and *will be passed through* as a separate credit on the bill. (Emphasis added.)

(Ex. 2 at Section 2, last ¶.)

With respect to the Centralia credit, the Rate Plan Stipulation is also clear:

> The Company *will return* to customers, as a separate credit on customers' bills, the gain from the sale of the Company's share of the Centralia plant. Such credit *shall be paid* during the five-year period commencing January 1, 2001 and continuing through December 31, 2005. . .The gain *to be returned* shall be the customers' share of the Centralia plant . . . The gain *shall be allocated* among the Company's Washington customers . . .on the basis of a uniform percentage of the customer bill, exclusive of taxes. (Emphasis added.)

(Ex. 2 at Section 4.)

141 The Company's deferred cost recovery proposal violates these express provisions. The Company states that:

> This proposal *removes* two credits that currently appear as separate line item adjustments on customers' bills. The Centralia Credit currently produces a average 2.8 percent reduction to customers' bills, while the Merger Credit results in a 1.7 percent reduction to customers' bills. The effect of *removing* these two credits *will increase customers' bills* by an average of 4.6 percent. (Emphasis added.)

(Ex. 90 at 2: 21 through 3: 2; Tr. 132.) The proposed tariff language also states that the Centralia and Merger credits "will not be applied to the customer's bill." (Ex. 93 at Schedule 97, Original Sheet 97-2 and Schedule 99.)

142 The Company argues that customers will receive the credits, but the credits will be off-set by the deferrals. (Tr. 127-28, 132-33.) That argument is disingenuous at best. The fact is that, under the Company's proposal, ratepayers will not receive the credits that they were promised under the Rate Plan Stipulation, and the Company will not be required to pay the credits that conditioned approval of the Centralia sale and the merger with Scottish Power.

B. Deferred Accounting (Ex. 2 at Section 9.)

143 Section 9 concerns the regulatory filings the Company may submit during the Rate Plan beyond the filings necessary to implement the agreed increases in general base rates. With respect to deferred accounting during the Rate Plan, Section 9 states:

> Section 9 does not preclude the Company from submitting petitions for accounting orders, as appropriate, for the treatment of revenues, investments or expenditures during the Rate Plan Period. *In this regard,* the Company shall ensure that items *currently treated as regulatory assets* under authorizations from other states that are proposed for inclusion in Washington at the end of the Rate Plan Period are supported by necessary accounting authorizations in Washington. (Emphasis added.)

The phrase "In this regard" was inserted with the specific intent to limit petitions for accounting orders during the Rate Plan exclusively to items that were treated as regulatory assets in other jurisdictions at the time the Rate Plan Stipulation was entered. (Ex. 101 at 8: 7 through 9: 2.) The power costs the Company seeks to defer beginning June 2002 do not fall into that category. Therefore, those costs may not be deferred under the terms of the Stipulation.

144 The Company, in fact, agrees with this interpretation. The Company understood that various regulatory assets and deferrals were being booked at the time in accordance with authorizations granted in other states. Section 9 was added to require the Company to obtain similar authorizations from the Commission prior to the Post Rate Plan Earnings Review. (Ex. 33.)

145 The Company seeks to deflect attention from its admission through Exhibit 111, which is a Staff memorandum recommending approval of a PacifiCorp request to capitalize and amortize the costs of early retirement and severance programs. The Staff memorandum is consistent with its interpretation of Section 9. The costs of the programs were on the Company's books at the time of the Rate Plan Stipulation under authorizations from other states. Staff's recommendation in Exhibit 111 achieved the necessary authorization in Washington. (Tr. 589-91 and 616.)

146 Finally, the Company suggested (Tr. 155), but only as an after-thought during cross-examination, that its proposal is allowed under

Section 9a of the Rate Plan Stipulation, which states that the Company may request tariff or rate changes for the:

> Impact of governmental or legislative actions, such as changes in Federal tax rates or changes in environmental laws or regulations.

(Ex. 2 at Section 9a.) The Company suggested that FERC's institution of rate caps in 2001 fell within Section 9a. (Tr. 223.)

147 When pressed, the Company admitted the error of that interpretation. (Tr. 247-49.) Moreover, such an interpretation would create an exception that would swallow the general rule of the Stipulation that general rates would be changed only under Section 2. The Company has already received all the rate changes specified in Section 2. (Tr. 139-40.)

C. Rate Plan Re-openers (Ex. 2 at Section 11.)

148 The Stipulation established a moratorium on changes to the Company's general base rates during the Rate Plan, except to implement under Section 2 the programmed increases for the years 2001, 2002 and 2003.

149 The Commission recognized, however, that the Company's financial health should be protected even if additional general increases are necessary during the Rate Plan. Therefore, the Commission approved

Section 11 to allow the Company to "re-open" the Rate Plan in case of an imminent and severe emergency. Section 11 states:

A *general rate case* filing during the Rate Plan Period may be made by the Company . . ., in the event of the following:

> a. Interim rate relief is warranted under the six-part standard adopted by the Commission in *WUTC v. Pacific Northwest Bell Telephone Company*, Cause No. U-72-30 (October 1972), and the Company *is requesting similar rate relief* in its two largest U.S. retail jurisdictions. (Emphasis added.)

(Ex. 2 at Section 11.)

150 In Sections III and IV, *supra*, we demonstrated that the Company did not meet the *PNB* standards with or without a Rate Plan. In this section, we substantiate two violations of Section 11 by the Company.

151 First, Section 11 requires the Company to file a general rate case in order to re-open the Rate Plan. Staff clarified this requirement when the Rate Plan Stipulation was presented:

> MR. ELGIN: . . . so interim rates are traditionally filed in the context of a general rate application, so we analyze what is the emergent need for rate relief so the company can maintain adequate and reliable service to the public, and then we process the remainder of the case.

(Ex. 44 at 867-868.) The Company, again, did not object to Staff's clarification of Section 11 and its underlying rationale.

152 The Company also admitted that it did not file a general rate case in this proceeding. (Tr. 135, 219.) It stated that it filed for "limited relief", rather than filing a general rate case with a request for interim relief, as the Stipulation expressly requires. (Ex. 1 at 7: 6-14; Ex. 8 at 2: 7-10.) It also stated that it could file a general rate case, in compliance with the Stipulation. (Tr. 246.)

153 Second, the Rate Plan Stipulation states that interim relief may be requested in Washington only if the Company "is seeking" similar rate relief in Utah and Oregon, the Company's two largest U.S. retail jurisdictions. The Company has not satisfied this requirement. It did not make contemporaneous filings seeking interim relief in Utah and Oregon at the time its request in Washington was filed.

154 This is not just a technical violation raised to deny PacifiCorp an avenue for rate relief. Since the Company must access external sources of capital for its utility operations across all of the jurisdictions where it operates, contemporaneous interim requests in Oregon and Utah are necessary to determine the immediate and essential cash needs of the Company. Washington should contribute its fair share to solving any financial crisis the Company faces. But, without contemporaneous requests in Utah and Oregon, the Commission cannot determine the

necessity and extent of Washington's contribution. (Ex. 101 at 14: 1-14; Ex. 104.) In fact, without contemporaneous filings, there can be no assurance that Washington is not already subsidizing other states.

155 The Company's filings for interim relief in 2001 in Utah and Oregon do not satisfy this requirement. Those prior requests utilized earlier test periods that are not contemporaneous with the costs and revenues the Company will currently experience in the context of its Washington request for interim rate relief. (Ex. 101 at 10: 13-16.) They are not probative of the Company's immediate and essential cash needs for external financing.[16]

D. Conclusion on Rate Plan Violations

156 These violations of the Rate Plan Stipulation are clear and important, but they are not the basis for Staff's recommendation to reject the Company's proposal in this case. They did, however, generate considerable controversy that occupied a considerable amount of time of the Commission and the parties.

---

[16] The Company's 2001 filing in Oregon also does not meet the requirement in Section 11 for "similar rate relief." The filing did not seek to meet standards that resemble the interim requirements of *PNB*. (Tr. 152.) The Oregon Commission rejected the Company's filing and quoted its Staff's conclusions that the Company's filing "lacked completeness, clarity and substance." The Oregon Staff also stated that the filing "failed to supply adequate information demonstrating why [PacifiCorp's] financial need for this rate increase was urgent." (Ex. 101 at 22: 3-18.)

157 That controversy could have been avoided had the Company admitted that its proposal violated the Rate Plan Stipulation, but that circumstances warrant amendment to the Stipulation. The Commission and the parties, then, could have focused solely on whether those circumstances did, in fact, exist.

VI. CONCLUSION

158 In order to succeed in this case, the Company has the burden to prove that:

- The power costs it seeks to defer are extraordinary;
- Washington is responsible for those power costs;
- The Company's financial condition faces immediate and severe jeopardy that necessitates recovery of those power costs in Washington; and
- The Company's proposal is either consistent with the Rate Plan Stipulation or justifies an amendment to the Stipulation.

159 The Company has failed to carry this burden of proof. The only extraordinary power costs that could be identified for the Deferral Period relate to the forward summer peaking contracts, but those contracts were entered to serve load outside of Washington.

The Company's financial condition is healthy and improving, in part, as a result of rate relief already granted in Washington.

160 The Company's proposal violates the Rate Plan Stipulation. The public interest does not warrant an amendment to accommodate that proposal. Nor does equity require the Commission to accept the Company's proposal in any shape or form.

DATED This 11th day of April, 2003.

Respectfully submitted,

CHRISTINE O. GREGOIRE
Attorney General

____

ROBERT D. CEDARBAUM
Senior Counsel