

BREFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE)
APPLICATION OF PACIFICORP)
FOR AUTHORITY TO)
IMPLEMENT A POWER COST)
ADJUSTMENT MECHANISM)

DOCKET NO. 20000-ET-03-205
Record No. 8581

PREFILED DIRECT TESTIMONY OF

Denise Kay Parrish

On Behalf of

The Office of Consumer Advocate

Filed January 30, 2004
Hearing March 15, 2004

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Denise Kay Parrish and my business address is 2515 Warren Avenue,
3 Suite 304, Cheyenne, Wyoming 82002.

4
5 **Q. WHAT IS YOUR OCCUPATION?**

6 A. I am currently the Deputy Administrator of the Wyoming Office of Consumer
7 Advocate (OCA). In this position, I review and provide input into the
8 recommendations made by the OCA. I review utility applications filed with the
9 Wyoming Public Service Commission (Commission) and provide advice to the
10 Administrator regarding the involvement the OCA should have, if any, in various
11 cases. I review applications, perform analyses and provide recommendations to
12 the Commission relative to various utility matters, including revenue
13 requirements, tariff language, competitive issues, rules and regulations, and other
14 items. I write and issue press releases, perform special studies, as well as provide
15 information and research to customers, the legislature, the OCA Administrator,
16 and others. I do other assignments and tasks, as needed and as assigned by the
17 OCA Administrator.

18
19 **Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL**
20 **BACKGROUND?**

21 A. In 1976, I graduated from Michigan State University with a Bachelor's degree in
22 Accounting. I have spent more than twenty-six years as a regulator of public
23 utilities, having been on the staff of four state utility regulatory commissions and
24 two consumer advocate entities. Twelve of these years have been spent at the
25 Wyoming Public Service Commission. I have taken classes related to various
26 aspects of public utility regulation, including income taxes, regulatory accounting,
27 capital recovery, cost-of-service, rate design, revenue requirements, separations
28 and allocations, and other specialized topics. I have taught classes on issues of
29 accounting standards, general ratemaking principles, affiliated transactions,
30 regulatory accounting, financial reporting, and other specialized topics to

1 regulatory professionals. For the past two years, I have been a member of the
2 faculty of the Michigan State University Institute of Public Utilities (CAMP
3 NARUC). I am the past chair and a current member of the National Association
4 of Regulatory Utility Commissioners' Staff Subcommittee on Accounting and
5 Finance. I am a member of the International WHO'S WHO of Professional
6 Management.

7

8 **Q. DO YOU HAVE EXPERIENCE AS AN EXPERT WITNESS?**

9 A. Yes. I have testified more than one hundred twenty-five times as an expert
10 witness. I have testified before the Michigan Public Service Commission, the
11 Colorado Public Utilities Commission, the Colorado District Court, the Arizona
12 Corporations Commission, the Wyoming Public Service Commission, and the
13 Wyoming Legislature Joint Corporations Committee. I have testified in
14 telecommunications, water, wastewater, electric, and natural gas cases. The
15 subjects upon which I have testified include fuel and purchased power adjustment
16 mechanisms, revenue requirements, rate design, cost-of-capital, nuclear
17 decommissioning, accounting deferrals, adjustment mechanisms, income taxes,
18 capital recovery, universal service funding, and other specialized topics.

19

20 **Q. DO YOU HAVE ANY EXPERIENCE WITH ADJUSTMENT**
21 **MECHANISMS SIMILAR TO THE SUBJECT OF THIS PROCEEDING?**

22 A. Yes. During the four years that I worked at the Michigan Public Service
23 Commission, my primary responsibility in the Electric Division was to audit and
24 review the Fuel and Purchased Power Cost Adjustment Mechanisms and their
25 associated computations of rate changes. This work included looking at the costs
26 that were incorporated into the mechanism – and the appropriateness of including
27 those costs. For the last two years that I was at the Michigan Public Service
28 Commission, I had the lead responsibility for this work.

29

30 Additionally, during my time at the Colorado Public Utilities Commission and the
31 Arizona Corporations Commission, I testified many times on issues related to fuel

1 and purchased power costs, the nature of the items that should be included in the
2 Electric Cost Adjustment Mechanisms, and other similar matters.

3
4 **Q. WHO DO YOU REPRESENT IN THIS PROCEEDING?**

5 A. As a member of the Office of Consumer Advocate, I represent the interests of
6 Wyoming citizens and all classes of utility customers in this public utility matter,
7 as required by W.S. § 37-2-401. It is neither my intent nor my charge to represent
8 the position of any individual group, municipality, or corporation.

9
10 **Q. WHAT COURSE OF ACTION IS AVAILABLE TO INDIVIDUAL**
11 **CONSUMERS OR OTHER INTERESTED PARTIES IF THEY WISH TO**
12 **PURSUE ISSUES NOT ADDRESSED BY THE OFFICE OF CONSUMER**
13 **ADVOCATE, OR TAKE A DIFFERENT POSITION FROM THE OFFICE**
14 **OF CONSUMER ADVOCATE?**

15 A. Customers and other parties may intervene in the proceedings and raise additional
16 issues not addressed by the Office of Consumer Advocate, and may take different
17 positions than those presented by the OCA. Consumers may also present written
18 or oral comments at the hearing, which then become part of the record in the case
19 and are available to the Commission as it makes its decision on any particular
20 proposal or suggested change. The OCA encourages the participation of the
21 public and all interested parties in cases before the Commission.

22
23 **Q. ARE YOU SPONSORING ANY SEPARATE OR ATTACHED EXHIBITS**
24 **OR SCHEDULES IN THIS PROCEEDING?**

25 A. No, I am not. The information I am presenting to the Commission is contained
26 within the body of my prefiled direct testimony.

27
28 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

29 A. The purpose of my testimony is to share with the Commission a number of
30 concerns regarding PacifiCorp's proposal to implement a Purchased Cost
31 Adjustment Mechanism (PCAM) and to offer some suggestions of how to

1 mitigate some, if not all, of those concerns. My testimony is presented in
2 conjunction with the testimony of Mr. Bryce Freeman, who provides the OCA's
3 policy concerns relative to PacifiCorp's proposal.
4

5 **Q. BEFORE ENUMERATING YOUR CONCERNS WITH PACIFICORP'S**
6 **PROPOSAL, PLEASE GENERALLY DESCRIBE THE RATEMAKING**
7 **CONTEXT IN WHICH THE PROPOSAL IS BEING MADE.**

8 A. PacifiCorp currently works within a very traditional regulatory scheme. When
9 PacifiCorp wishes to change its rates, it has to date, filed a general rate case. This
10 general rate case is based on the following formula:
11

$$12 \text{ Revenues} = \text{Expenses} + \text{Depreciation} + \text{Taxes} + (\text{Investment} \times \text{Allowed Rate of Return})$$

13
14 The expenses included in the formula include operating expenses (such as
15 maintenance, fuel, transmission, field labor, etc.) as well as administrative
16 expenses (such as office supplies, insurance, office salaries, etc.)
17

18 The depreciation allows for the orderly and systematic recognition over time of
19 the cost of the investment necessary to provide utility service and allocates that
20 investment to the period that it is used. It often is said to be the means by which
21 the utility's investment is returned to it.
22

23 The taxes included in rates include income taxes, property taxes, franchise fees,
24 and other taxes necessarily paid in the conduct of business.
25

26 The investment upon which the utility is allowed to earn a return is frequently
27 called its *rate base*. This is the investment necessary for the provision of service,
28 and is actually up and running, or *used and useful*, meaning that it is providing
29 benefits to ratepayers during the period of time under consideration. It includes
30 plant and equipment (reduced for accumulated depreciation levels), materials and
31 supplies, prepaid expenses (such as insurance), and other, miscellaneous assets. It

1 excludes the investments funded by customer money (such as customer advances,
2 customer deposits, etc.)
3

4 Finally, the allowed rate of return is a figure established by the Commission that
5 allows the utility to recover its debt costs. It also allows for a profit margin based
6 on the estimated level of return expected by investors based on looking at
7 alternative investments of similar risk.
8

9 When all of these items are totaled, the result is the overall revenues that are
10 required by the utility in order to pay reasonable on-going expenses, recover its
11 capital investment, and earn a return on investment. This total, often called either
12 a *revenue requirement* or a *cost of service* is established on a normalized basis
13 (excluding one-time items or anomalies) and on a going-forward basis, wherein
14 an attempt is made to represent the period that the rates are expected to be in
15 effect.
16

17 This ratemaking method is commonly called a rate base, rate-of-return method,
18 while others have referred to it as a *cost plus* method of setting rates.
19

20 This total revenue number is then allocated to the individual rate groups or rate
21 classes (residential, commercial, irrigation, industrial, etc.). The last step in the
22 rate process is then to establish the specific rate levels and prices for each class of
23 customers. Ultimately, there will be a determination of the appropriate monthly
24 customer charge, the demand charges, the per unit energy charge, and any other
25 surcharges or credits to be passed on to customers.
26

27 Under the current ratemaking process used for PacifiCorp, and most (if not all)
28 other Wyoming electric and gas utilities, the established rates remain in effect
29 until changed. The changes would generally occur for one of two reasons. In one
30 case, which occurs rarely, the Commission could enter into a process to reduce
31 rates on a basis involuntary to the utility. This would generally occur when the

1 Commission acquires reliable information that the company is earning at
2 unreasonably high levels. In the second, more common instance, the utility would
3 file an application before the Commission to change its rates (generally an
4 increase but sometimes voluntary decreases have been requested) because of the
5 utility's belief that it is not recovering its costs and earning a reasonable return on
6 its investment. Rates are only changed upon an order of the Commission.

7

8 **Q. WHY DO YOU BELIEVE THAT A GENERAL KNOWLEDGE OF THE**
9 **RATEMAKING PROCESS IS IMPORTANT TO UNDERSTAND THE**
10 **REQUEST IN THIS PROCEEDING?**

11 A. It is important because the request is a significant departure from PacifiCorp's
12 historic ratemaking practices in Wyoming.

13

14 Under PacifiCorp's historic practices, generally described above, the Company
15 took the risk of changes in costs between rate cases. A normalized set of costs
16 was included in the computation of the rates. If the costs increased after the rates
17 were established, PacifiCorp had to bear those cost increases until it could file
18 another rate case and get approval to increase rates. It could not arbitrarily
19 increase rates to track the increased costs. Similarly, if its revenues decreased it
20 could not make up for that loss from the other customers without going through
21 the pains of a rate case. If costs decreased, PacifiCorp and its shareholders
22 received the benefit of those decreases until costs rose again or steps were taken,
23 by PacifiCorp or the Commission, to reduce its rates.

24

25 However, it would be rare for an increase or decrease in one item to drive a
26 change in the overall rate. The rates are a combination of all of the costs, although
27 some have more of an impact on the total rate, and on PacifiCorp's earnings, than
28 others. But, overall, PacifiCorp had some incentive to control its costs, since
29 general rate cases can be time consuming with no assurance of what the outcome
30 will be. And, many claimed cost increases may not be accepted due to prudence
31 determinates, timing issues, etc.

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It would not be uncommon for some costs to increase during a period, while other costs decreased (or at least stabilized), providing some balance and dampening effect on the need for continuous rate changes.

Q. WAS REGULATORY LAG ALSO BUILT INTO THE REGULATORY PROCESS?

A. Yes. This is aptly described in the book *Performance-Based Ratemaking: Theory and Practice* by Dr. Michael R. Schmidt¹ (published by Public Utilities Reports, Inc., 2000), at pages 13-14:

Rate of return regulation has generally been credited with achieving lower than monopoly prices and higher than monopoly output levels. Dr. Alfred Kahn pointed out this fact:

Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.

Thus, regulatory lag has been and continues to be a useful tool of the regulatory process as an incentive for more cost-effective or efficient management and can serve as a deterrent to waste and inefficiency. The lag requires management to take a careful look at the expenditures made for a given level of sales and a given set of prices. The lack of immediate recovery (or no recovery at all if the expenditure is not incorporated into a future rate case) serves as an incentive for prudence and mitigation of inappropriate expenditures . . .

Under its proposal, PacifiCorp would not immediately be able to change its rates to customers as costs changed, but the effect would be similar. It would be assured the same dollar-for-dollar recovery as if it were able to change its rates the instant that its costs changed – at least for the items that are selected to be isolated as part of the proposed mechanism.

¹ Dr. Schmidt is a Regulatory Policy Leader at Sempra Energy’s corporate headquarters in San Diego and is also an adjunct professor of business administration at University of Phoenix – San Diego and teaches graduate and undergraduate courses in micro- and macroeconomics, finance, and project analysis.

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Q. WHAT HAPPENS WHEN ONE COST, OR ONE SET OF COSTS, IS ISOLATED FROM THE OTHER COSTS, AND IS SELECTED TO BE RECOVERED ON A DOLLAR-FOR-DOLLAR BASIS?

A. The dampening effect – or averaging of increases and decreases – is lost. The incentive to control a discrete isolated cost is also diminished. And, finally, the shareholders no longer bear the risk that was associated with the potential changes in that one cost. That risk has now been shifted to ratepayers, who will have to bear whatever cost changes occur.

Q. DO OTHERS SUPPORT YOUR VIEW THAT ADJUSTMENT MECHANISMS REDUCE DESIREABLE INCENTIVES?

A. Yes. In 2000, the Regulatory Assistance Project² issued a paper titled *Best Practices Guide: Implementing Power Sector Reform*. At page 55 of the paper, Fuel Adjustment Clauses are discussed:

Fuel adjustment clauses (FAC) are common in many regulatory schemes. Although the details differ from jurisdiction to jurisdiction the basic operation is to hold utilities harmless from the financial effect of fuel costs. The terms frequently used with a FAC are that fuel costs *flow through* or *pass through* to customers.

There are many justifications given for FACs, but the fact remains that FACs move in the opposite direction of rewarding incentives to improve performance and cut costs. Fuel adjustment clauses generally remove the incentive for any genuine efficiency, they remove the incentive for reduction of line losses and then to skew the trade-off between capital and operating costs and reduce any incentive for owners to invest in portfolios that diversify fuel mixes.

Q. IS THIS THE PRIMARY CONCERN OF THE OCA?

A. Yes. In conjunction with the shift in risk described by Mr. Freeman in his testimony, we are concerned about the insulation from incentives that a dollar-for-

² The Regulatory Assistance Project is a non-profit organization, formed in 1992, that provides workshops and education assistance to state public utility regulators on electric utility regulation. According to its website (<http://www.raponline.org>), The Regulatory Assistance Project is committed to fostering regulatory policies for the electric industry that encourages economic efficiency, protect environmental quality, assure system reliability and allocate system benefits fairly to all customers.

1 dollar mechanism provides PacifiCorp. If the Commission allows PacifiCorp
2 some form of PCAM, it must incorporate continued incentives to control costs
3 and it must not shift all of the risk of cost increases to ratepayers. PacifiCorp's
4 proposal does not adequately incorporate incentives or risk sharing mechanisms,
5 and must not be adopted as proposed.

6
7 **Q. WAS PACIFICORP DIRECTED BY THE COMMISSION TO FILE A**
8 **PURCHASED COST ADJUSTMENT MECHANISM OR SIMILAR**
9 **RATEMAKING PROPOSAL?**

10 A. No, In Docket No. 20000-ER-02-184, there was discussion, both at the hearing
11 and in the written order, of the fact that PacifiCorp did not have such a
12 mechanism, and thus, the decision was different than it might otherwise have
13 been. (Interestingly, the cost recovery decision might have also been the same,
14 since prudence reviews continue to be appropriate even when a PCAM exists.)
15 The record clearly indicates that it was PacifiCorp's choice not to have such a
16 mechanism.

17
18 **Q. WHY ALLOW ANY COSTS TO BE TREATED DIFFERENTLY --**
19 **ESPECIALLY ON A SELECTIVE BASIS?**

20 A. Many state regulators have allowed special provisions for selective costs based on
21 the unique characteristics of those costs, such as: significance/size, volatility,
22 impact on the overall corporate financial condition, company's ability to control
23 the costs, etc. I agree with the general characterization of the type of costs to be
24 included a PCAM as described in the testimony of Mr. Wendell Winger of the
25 Staff of the Colorado Public Utilities Commission in Docket No. 02S-594E³:

26 In past decisions the Commission has expressed criteria it has used
27 for the evaluation of fuel clauses. In Decision No. C95-248,
28 Docket No. 93-702E, the Commission agreed with Staff that the
29 following factors should be present in order to justify the
30 maintenance of a fuel clause:

- 31 1) fuel costs must be significant;
32 2) fuel costs must be volatile;

³ The Investigation and Suspension of Tariff Sheets Filed by Aquila, Inc., Doing Business as Aquila Networks –WPC, With Advice No. 579. Testimony filed February 18, 2003.

- 1 3) fuel costs must be beyond the control of the
2 company; and
3 4) fuel costs must have increased in price greater than
4 the rate of inflation.
5

6 The OCA agrees that costs should have *each of* the above characteristics to even
7 be considered for special treatment – treatment separate and apart from the normal
8 regulatory regime. However, incentives and risk shifting must also be considered.
9

10 **Q. ARE THERE OTHER CRITERIA THAT MUST BE CONSIDERED BY**
11 **THE COMMISSION WHEN DECIDING WHETHER TO GRANT**
12 **PACIFICORP’S REQUEST IN THIS CASE?**

13 A. Yes. One of the Commission’s procedural rulings in this case, as well as
14 PacifiCorp’s own clarifications, advise that the PCAM being requested in this
15 proceeding is not confined to the language of Sections 249 and 250 of the
16 Commission’s rules. Instead, the PCAM is described as having aspects of a
17 balancing account, a pass-on of commodity costs, and nontraditional ratemaking.
18 The nontraditional ratemaking standards in Wyoming are set forth in W.S. § 37-2-
19 121:

20 . . . Any public utility may apply to the commission for its
21 consent to use innovative, incentive or nontraditional rate making
22 methods. In conducting any investigation and holding any hearing
23 in response thereto, the commission may consider and approve
24 proposals which include any rate, service regulation, rate setting
25 concept, economic development rate, service concept,
26 nondiscriminatory revenue sharing or profit-sharing form of
27 regulation and policy, including policies for the encouragement of
28 the development of public utility infrastructure, services, facilities
29 or plant within the state, which can be shown by substantial
30 evidence to support and be consistent with the public interest.
31

32 It is paramount that any proposal approved by the Commission support and be
33 consistent with the public interest.
34

35 **Q. PLEASE DESCRIBE THE PCAM THAT HAS BEEN PROPOSED BY**
36 **PACIFICORP.**

1 A. PacifiCorp Witness Widmer describes the mechanism starting at page 6 of his
2 prefiled direct testimony and states, in part:

3 The PCAM is an incentive-based mechanism that includes two
4 components: (1) an annual update which recovers forecast NPC
5 [net power costs] through a surcharge, and (2) a deferral
6 mechanism that shares variations in adjusted actual net power costs
7 from forecasted NPC between customers and shareholders. The
8 deferral component of the mechanism includes a dead band and
9 two sharing bands, which straddle the baseline NPC forecast for
10 the upcoming year. The dead band extends from the baseline NPC
11 forecast to 4.5 percent above and 4.5 percent below the baseline
12 NPC forecast. When adjusted actual NPC falls within the dead
13 band, there would be no deferral. The first sharing band would
14 extend from the dead band to 9.0 percent above the dead band and
15 9.0 percent below the dead band. Adjusted actual NPC that falls
16 within the first sharing band would be split 80 percent/20 percent
17 between customers and shareholders . . . Beyond the first sharing
18 band, adjusted actual NPC would be split 95 percent / 5 percent
19 between customers and shareholders to provide insurance against
20 extremely high costs that occur when industry products are
21 unavailable or the Company is unable to mitigate high costs.

22
23 **Q. HAS PACIFICORP DEFINED NET POWER COSTS?**

24 A. I have not found any definition of net power costs in the application or Mr.
25 Widmer's testimony. However, in Docket No. 20000-ER-03-198, Mr. Widmer
26 did include a definition of net power costs on page 2 of his prefiled direct
27 testimony:

28 Net power costs are defined as the sum of fuel expenses, wholesale
29 purchase expenses and wheeling expenses, less wholesale sales
30 revenue.
31

32 **Q. ARE THERE SPECIAL CONSIDERATIONS THAT SHOULD BE TAKEN**
33 **INTO ACCOUNT WHEN CONSIDERING AN ADJUSTMENT**
34 **MECHANISM FOR AN ELECTRIC UTILITY THAT GENERATES**
35 **MOST OF ITS OWN POWER?**

36 A. Yes. Some of the unexpected results that come from applying a PCAM type
37 mechanism to a generating utility are best described with an illustration.
38
39

1 Assume the following is an illustration of a typical Wyoming utility that utilizes
2 the Commission's allowed pass-on procedures:

- 3 • Company A purchases all of its power from a third party (i.e., arm's length
4 transaction).
- 5 • Company A has a power cost adjustment mechanism.
- 6 • Sixty percent of Company A's revenue requirement is comprised of
7 purchased power costs.
- 8 • The purchased power costs for Company A increase by 25%.
- 9 • As a result, the rates for Company A's customers increase by 15%.
- 10 • Company A's revenues increase by 15%, thus increasing its cash inflow.
- 11 • By the precise amount that Company A's revenues increased, its cash out
12 flow increased.
- 13 • The result is a zero cash flow increase and a zero impact on earnings.

14
15
16 In contrast, assume the following is an illustration of a Wyoming generating
17 utility:

- 18
19 • Company B purchases 15% of its energy needs in the wholesale market
20 and generates 85% of its needs.
- 21 • Company B has a comprehensive PCAM covering both market purchases
22 and fuel for self-generation.
- 23 • Thirty percent of Company B's revenue requirement is comprised of fuel
24 and purchased power costs.
- 25 • The purchased power costs for the company increase 25%.
- 26 • The fuel costs for Company B increase by 15% but the increase is due to
27 internal operational costs (e.g., repairs for the conveyor belt unloading
28 coal into the coal pile) that are accounted for in the cost of coal.
- 29 • As a result, the rates for Company B's customers increase by 5%.
- 30 • Company B's revenues and cash inflow increase by 5%.
- 31 • Company B's cash outflow only increases by 1.2%, the amount of the
32 increase in the purchased power costs by outside vendors (30% of revenue
33 requirement x 15% purchased power x 25% increase).
- 34 • Company B's cash inflow has a net increase of 3.8%.
- 35 • The conveyor belt is repaired by Company B's internal maintenance
36 people, whose salaries are already recovered through general rates, and not
37 requiring payments to outside vendors.
- 38 • The 3.8% increase in rates flows directly to Company B's bottom line,
39 thus increasing its profits and earned rate of return.

40
41 As shown by the example above, one of the concerns of the PCAM comes from
42 routine operations – not only catastrophic events such as the loss of a major power
43 plant from the system. Additionally, the cost of fuel includes much more than
44 simply the commodity cost paid to a third party. One can no longer assume that

1 all of the cost increases are external to the utility, not under the company's control
2 to the same degree, or that the pass through will have no impact on the return of
3 the utility.

4

5 **Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE COST OF THE**
6 **COAL AS IT GOES INTO INVENTORY?**

7 A. Account 151 is titled *Fuel Stock (Major only)*. This is the account that the cost of
8 the coal is in when it moves into the coal piles located at the power plant. The
9 following is the account description, which includes examples of the types of
10 costs to be included:

11 This account shall include the book cost of fuel on hand.

12 *Items*

- 13 1. Invoice price of fuel less any cash or other discounts.
- 14 2. Freight, switching, demurrage and other transportation
15 charges, not including, however, any charges for unloading
16 from the shipping medium.
- 17 3. Excise taxes, purchasing agents' commissions, insurance
18 and other expenses directly assignable to cost of fuel.
- 19 4. Operating, maintenance and depreciation expenses and ad
20 valorem taxes on utility-owned transportation equipment
21 used to transport fuel from the point of acquisition to the
22 unloading point.
- 23 5. Lease or rental costs of transportation equipment used to
24 transport fuel from the point of acquisition to the unloading
25 point.

26

27 **Q. ARE THERE ADDITIONAL COSTS OF FUEL INCLUDED IN THE FUEL**
28 **EXPENSE ACCOUNT THAT IS RECORDED ON THE UTILITY'S**
29 **INCOME STATEMENT?**

30 A. Yes, and many of these individual cost components are not the type of item that
31 are subject to cost volatility nor are they items that individually would be
32 considered to be outside the utility's control (e.g., depreciation and maintenance).
33 A general listing of these costs is included with the description of Account 501,
34 *Fuel*;

- 35 1. Supervising purchasing and handling of fuel.
- 36 2. All routine fuel analysis.
- 37 3. Unloading from shipping facility and putting in storage.

- 1 4. Moving of fuel in storage and transferring fuel from one station to
- 2 another.
- 3 5. Handling from storage or shipping facility to first bunker, hopper,
- 4 bucket, tank or holder of boiler-house structure.
- 5 6. Operation of mechanical equipment, such as locomotives, trucks,
- 6 cars, boats, barges, cranes, etc.
- 7 7. Operating, maintenance and depreciation expenses and ad valorem
- 8 taxes on utility-owned transportation equipment used to transport
- 9 fuel from the point of acquisition to the unloading point (Major
- 10 only).
- 11 8. Lease or rental costs of transportation equipment used to transport
- 12 fuel from the point of acquisition to the unloading point (Major
- 13 only).
- 14 9. Cost of fuel including freight, switching, demurrage and other
- 15 transportation charges.
- 16 10. Excise taxes, insurance, purchasing commissions and similar
- 17 items.
- 18 11. Stores expenses to extent applicable to fuel.
- 19 12. Transportation and other expenses in moving fuel in storage.
- 20 13. Tools, lubricants and other supplies.
- 21 14. Operating supplies for mechanical equipment.
- 22 15. Residual disposal expenses less any proceeds from sale of
- 23 residuals.
- 24

25 **Q. DO YOU AGREE WITH MR. WIDMER THAT THE NET POWER**
26 **COSTS ARE LARGELY OUTSIDE THE COMPANY'S CONTROL?**

27 A. No. As shown below, of the actual net power costs shown in the Company's most
28 recent Wyoming rate filing, 58% of them were associated with the cost of
29 generating power with coal. (See Results of Operation, Page 5.2.1, Docket No.
30 20000-ER-03-198) Yet, in that same document, at page 8.4, PacifiCorp states:

31 PacifiCorp owns a 21.47 percent interest in the Trapper Mine,
32 which provides coal to the Craig generating plant. . .PacifiCorp
33 owns two-thirds interest in the Bridger Coal Company, which
34 supplies coal to the Jim Bridger generating plant.

35 These statements seem to contradict Mr. Widmer's statement that the net power
36 costs are largely outside of the Company's control. A significant portion of the
37 net power costs come from two coal mines owned by PacifiCorp.

38

1 **Q. DO YOU HAVE OTHER CONCERNS ABOUT THE USE OF A PCAM BY**
2 **A GENERATING COMPANY?**

3 A. Yes. A generating utility, such as PacifiCorp, has less need for a PCAM than
4 does a company that purchases all of its energy. Furthermore, a generating utility
5 has more opportunity to affect its own fate, than does a utility that is bound to
6 purchase of all its power from the open market.

7
8 **Q. PLEASE EXPLAIN WHY A COMPANY SUCH AS PACIFICORP HAS**
9 **LESS NEED FOR A PCAM THAN DOES A UTILITY THAT HAS NO**
10 **ABILITY TO GENERATE ANY OF ITS POWER.**

11 A. A generating utility, particularly PacifiCorp, has a diverse fuel supply such that it
12 lessens the impact of events affecting either its power or fuel supply. For
13 instance, one can look at power cost information from the pending PacifiCorp rate
14 case (Docket No. 20000-ER-03-198; test year ended September 2002) and find
15 the following break down of net power costs:

16

17	Actual Sales for Resale	\$ 987,179,243	
18	Purchased Power Expense	\$1,109,100,185	
19	Net Purchases	\$ 121,920,942	17%
20	Wheeling	\$ 90,633,090	13%
21	Fuel Consumed – Coal	\$ 400,856,933	58%
22	Undistributed Fuels Credit	\$ (23,604,100)	(3%)
23	Fuel Consumed – Gas	\$ 39,338,792	6%
24	Steam from Other Sources	\$ 3,698,549	1%
25	James River Royalty Offset	\$ 52,305,376	8%
26	NET POWER COST	\$ 685,149,583	

27

1 This chart shows that only 17% of PacifiCorp’s net power costs were subject to
2 the wholesale power market⁴. And, only 6% of PacifiCorp’s net power costs are
3 subject to the volatility of the gas market. Thus, even if gas prices were to
4 double, PacifiCorp’s net power costs would only increase by less than six percent.
5 This would be an increase to revenue requirements of about 1.5%.

6
7 Similarly, if the total annual purchased power expense were to double from
8 current levels (meaning increases not only at the peak, but on average for all
9 hours of the day), the total net power costs would only increase by less than 18%.
10 And, since Mr. Widmer indicates in his testimony that net power costs are about
11 25% of the total revenue requirement, the doubling of net purchase costs would be
12 a total increase in PacifiCorp’s revenue requirement of only 4.5%.

13
14 A significant change in the coal cost would be more troubling, but is far less
15 likely. PacifiCorp has recently indicated before the Commission that it has long-
16 term coal contracts, with price reopeners that have been used to recently reduce
17 prices. Additionally, as noted above, PacifiCorp owns a portion of its coal
18 resources used to fuel two of its own power plants.

19
20 **Q. IS THIS CONSISTENT WITH MR. WIDMER’S VIEW?**
21 **A.** No. In his testimony, at page 2, Mr. Widmer states, “The Company believes net
22 power costs will continue to fluctuate in the future.” But, he does not explain what
23 the levels of fluctuations will be, the basis of his belief, or most importantly, if
24 these fluctuations will only impact a small portion of the overall net power cost.

25
26 In his testimony, Mr. Widmer focuses on the cost of purchased power and the
27 recent volatility of those costs. Yet, as explained above, the impact of these cost
28 increases, should they continue, would be greatly mitigated by the fuel diversity
29 in place on PacifiCorp’s system. Additionally, PacifiCorp has recently entered

⁴ Mr. Widmer’s testimony shows an even smaller amount of the system being subject to extreme volatility since he focuses only on short-term purchases, and not all purchases. (See page 6 of the prefiled testimony of Mr. Widmer.)

1 into several hedges (the hydro hedge and the temperature hedge) that will assist
2 in mitigating the cost of any unusual market purchases. There is no discussion in
3 Mr. Widmer's testimony as to what the overall impact on net power costs would
4 be from the kind of fluctuations he only generally describes.
5

6 **Q. DOES A GENERATING UTILITY HAVE MORE OPPORTUNITY TO**
7 **CONTROL ITS POWER COSTS THAN A UTILITY ENGAGED ONLY IN**
8 **PURCHASING ITS POWER?**

9 A. Yes. If a generating utility chose to defer maintenance on a power plant, causing a
10 less efficient burn of fuel, the higher cost of that fuel would then be recoverable
11 through the type of PCAM proposed by PacifiCorp in this proceeding. If done in
12 small increments, or subtle rather than blatant ways, it would be difficult for a
13 regulator, given time and resource constraints, to notice this change in operating
14 procedure.
15

16 Similarly, it is difficult for regulators to review each and every operating decision
17 of the Company that comprise the actual net power costs that are proposed by
18 PacifiCorp to be recoverable through the PCAM. It would, therefore, be very
19 difficult for regulators to know if a generating utility had chosen to burn coal that
20 might be subject to a take-or-pay contract, rather than purchasing lesser priced
21 power on the wholesale market.
22

23 Whether or not subtle operating shifts actually occurred, the incentive would
24 certainly exist for a generating utility to shift its practices to those costs that
25 would be entirely recoverable, in lieu of the operating practices that might result
26 in the lowest overall price for customers. This would be the difference between
27 minimizing total operating costs (net power costs and costs only recoverable in a
28 general rate proceeding) or only minimizing net power costs.
29
30
31

1 **Q. YOU HAVE PROVIDED SEVERAL ANALYSES OF THE BREAKDOWN**
 2 **OF NET POWER COSTS AND THE IMPACT THAT WOULD OCCUR**
 3 **FROM INCREASING THE COST OF VARIOUS ELEMENTS OF THOSE**
 4 **COSTS. WHAT ASSURANCE CAN YOU PROVIDE THAT THE**
 5 **BREAKDOWN OF THE NET POWER COSTS FROM THE RECENT**
 6 **RATE CASE IS REPRESENTATIVE OF NORMAL PACIFICORP**
 7 **OPERATIONS?**

8 A. First, the above power costs represent the actual breakdown of net power costs
 9 that occurred during the test year for the most recent rate case. So, this is the
 10 most recent actual data available.

11
 12 Second, as a check on the recent data, I examined similar data from an earlier
 13 time frame. Taking similar data from Docket No. 20000-EP-00-162, a rate case
 14 involving a 1999 test year, I arrive at the following results:

15	Actual Sales for Resale	\$1,029,080,651	
16	Purchased Power Expense	\$ 894,769,222	
17	Net Purchases	\$ (134,311,429)	(31%)
18	Wheeling	\$ 71,334,239	17%
19	Fuel Consumed – Coal	\$ 461,057,638	106%
20	Undistributed Fuels Credit	\$ (19,899,591)	(5%)
21	Fuel Consumed – Gas	\$ 49,867,264	12%
22	Steam from Other Sources	\$ 9,362,235	2%
23	James River Royalty Credit	\$ (5,666,133)	(1 %)
24	NET POWER COST	\$ 431,744,223	

25
 26 In this test year, 1999, coal – the most stable fuel cost incurred by PacifiCorp --
 27 comprised more than 100% of the net power costs. If this test year were
 28 representative of actual costs in future periods, there would be very little risk
 29 associated with the Company’s overall net power costs.
 30

1 If one removed the offset to power costs reflected by the negative 31% proportion
2 on the above chart, and looked only at the proportion that coal costs constitute of
3 the remaining costs, coal costs become 81% of the total. This is still a large
4 proportion and a very stabilizing factor in the net power costs.
5

6 **Q. IN LIGHT OF THE CONCEPTUAL CONCERNS THAT YOU HAVE**
7 **RELATIVE TO THE USE OF A PCAM BY PACIFICORP, WHAT IS**
8 **YOUR RECOMMENDATION TO THE COMMISSION?**

9 A. The primary recommendation of the OCA is that the Commission deny
10 PacifiCorp's request to implement its proposed PCAM. The above testimony
11 shows that there is little risk to PacifiCorp in continuing without a PCAM, but a
12 significant potential risk to ratepayers of approving the one proposed. There is no
13 evidence that PacifiCorp will bear an unreasonable financial burden if it continues
14 with its existing regulatory regime.
15

16 **Q. ARE YOU ALSO RECOMMENDING THAT A REGULATORY SAFETY**
17 **NET BE ESTABLISHED IN CASE THERE ARE UNUSUAL**
18 **CIRCUMSTANCES THAT UNEXPECTEDLY HAVE A LARGE,**
19 **NEGATIVE IMPACT ON PACIFICORP'S NET POWER COSTS?**

20 A. Yes. The Commission should authorize a procedure whereby PacifiCorp could
21 easily implement a mechanism that would provide a safety net if it were really
22 needed, but would otherwise lie dormant. Along this line, I have three alternative
23 suggestions to offer the Commission:

24 1. Simply allow PacifiCorp to begin deferring net power costs if
25 changes occur that have a significant, negative impact on the
26 totality of the net power costs (rather than just one of the elements)
27 and those cost changes are caused by outside forces (e.g., a long
28 labor strike at the mines that supply PacifiCorp coal).

29 2. Determine the nature and details of a PCAM that would not be
30 used on a day-to-day basis, but would only be activated if certain
31 conditions or events occurred.

1 3. Reject PacifiCorp’s proposed PCAM, and instead, implement a
2 mechanism that contains greater incentives for the Company to
3 control its overall costs (not just net power costs) and reasonably
4 shares risk between customers and shareholders.
5

6 **Q. PLEASE EXPLAIN YOUR ALTERNATIVE THAT WOULD AGAIN**
7 **ALLOW PACIFICORP TO DEFER NET POWER COSTS IF**
8 **CIRCUMSTANCES WARRANTED.**

9 A. Under current accounting conventions, a cost that would normally be treated as an
10 expense may be deferred and amortized over future periods if there is reasonable
11 probability of recovery. While personally I believe that the deferral process is
12 used too often for costs that do not merit special treatment, I believe there are
13 times when a deferral and amortization is the proper treatment, such as a situation
14 where Western wholesale market costs during superpeak hours were to increase
15 multiple-fold, for more than just a day or two, and the cost increases were not
16 incurred as a result of PacifiCorp’s own decision making process.
17

18 The Commission has shown that it can approve an application for deferral in a
19 relatively quick timeframe (less than 30 days). Once costs have been defined as
20 appropriate for deferral, and begin being set aside in PacifiCorp’s books and
21 records, PacifiCorp’s risk then becomes one of passing the prudence test
22 regarding those deferred costs. Parties should always have a right to investigate
23 the appropriateness of costs for which recovery is sought from ratepayers.
24

25 The deferral option provides a safety net without the need to formulate a specific
26 regulatory mechanism that would be burdensome to parties during a timeframe
27 when it would not be needed to protect PacifiCorp from unreasonable business
28 risks.
29

1 **Q. PLEASE DESCRIBE YOUR ALTERNATIVE THAT WOULD CREATE A**
2 **PCAM THAT WOULD ONLY BE USED IF NEEDED AND IF SPECIFIC,**
3 **PREDEFINED TRIGGERS WERE REACHED.**

4 A. As described in the earlier portion of my testimony, the OCA is concerned that
5 there is not a proven, on-going need for a PCAM given the portion of the fuel
6 costs under PacifiCorp's control, the fuel diversity it has, the relative stability of
7 the wholesale power markets, and PacifiCorp's more recent elimination of
8 speculation from its power purchasing activities. There is no need to subject
9 customers to a regulatory regime with fewer incentives, less stable rates, fewer
10 shareholder risks, and more regulatory burdens. However, if the Commission is
11 convinced that: the current characteristics of PacifiCorp's net power costs are not
12 likely to continue into the future, and that there is a real potential that the totality
13 of the net power costs will become less stable and more volatile, that there is a
14 strong probability that the cost changes will be substantial, and that the cost
15 changes will be driven by forces external to the Company's decision making, then
16 it would be reasonable to develop a PCAM that could be put into place if needed.
17 This mechanism should essentially have all of its elements developed and ready to
18 go, so that the parties will not have to hash out the details before the Commission
19 during a power crisis or other emergency. The most important of these details
20 would be the establishment of appropriate triggers that would activate the PCAM.

21
22 **Q. CAN YOU PROVIDE AN EXAMPLE OF AN APPROPRIATE TRIGGER?**

23 A. An appropriate trigger might be when projected net power costs exceed a certain
24 percentage of the net power costs that have been included in PacifiCorp's rate
25 computation. Mr. Widmer indicates that net power costs are currently about 25
26 percent of PacifiCorp's total revenue requirement. If those costs were to increase
27 in total by 40 percent, they would become about 35 percent of the total revenue
28 requirement – an increase of ten percent. This could be substantial enough to
29 warrant the implementation of the previously established, but inactive PCAM.
30 The PCAM could then be used to get PacifiCorp through the unusual or
31 emergency period, until either the unusual circumstances subsided, or PacifiCorp

1 could file a rate case in order to reflect the higher net power costs on a more
2 permanent basis in on-going rates.

3

4 **Q. WAS THE ABOVE SUGGESTED TRIGGER MEANT TO BE**
5 **ILLUSTRATIVE OR DEFINITIVE?**

6 A. The above trigger discussion was illustrative. I am sure that if asked, others
7 would have their own ideas about what the appropriate trigger should be.

8

9 If the Commission decided to adopt the OCA suggestion of creating a PCAM that
10 would only be activated when needed, I suggest the following process for
11 assembling the details of such a mechanism. The Commission would announce
12 that it had reached a conceptual decision to adopt an emergency-only PCAM.
13 Then, it would direct that PacifiCorp meet with the interested parties on a fairly
14 short timeframe (e.g., 30 days) in order to try to reach agreement on a common
15 process and set of triggers that would warrant the PCAM's activation. After
16 consulting with the parties, PacifiCorp would then file its detailed proposal with
17 the Commission in the form of a tariff – a tariff that would need ultimate
18 Commission approval.

19

20 **Q. AREN'T YOU JUST ASKING FOR ANOTHER ROUND OF**
21 **DISAGREEMENTS AMONG THE PARTIES WITH YOUR SUGGESTED**
22 **PROCESS?**

23 A. No. It is my belief that once given general direction by the Commission on the
24 preferred conceptual approach, the parties involved in this case would be
25 cooperative in putting together a detailed proposal consistent with the
26 Commission's more general direction. That proposal, which should be directed to
27 be prepared in a fairly short time frame, would then be submitted for Commission
28 approval.

29

30 **Q. PLEASE FURTHER EXPLAIN THE LAST OF YOUR THREE**
31 **SECONDARY ALTERNATIVES.**

1 A. This alternative would accept the portion of PacifiCorp’s proposal that asks that a
2 PCAM be implemented now, with some portion of net power costs allowed to be
3 passed on between rate cases. However, to offset the shifting of additional risk to
4 ratepayers that would occur if PacifiCorp’s plan were to be implemented, further
5 provisions would be included in the PCAM that contained more potential benefits
6 for ratepayers. There are many forms that such a proposal could take.

7

8 **Q. IF THE COMMISSION IS INCLINED TO ACCEPT YOUR SECONDARY**
9 **SUGGESTION OF PUTTING A PCAM INTO PLACE BUT WITH**
10 **MODIFIED PROVISIONS, WHAT PROCESS DO YOU RECOMMEND?**

11 A. If the Commission was to accept this suggestion of modifying the make-up of the
12 PCAM to make it more balanced, the OCA suggests that a second-phase of the
13 proceeding be established to receive input on what the best provisions might be –
14 especially since there are a wide variety of provisions currently in use around the
15 country. Allowing the parties a relatively short time (45 to 60 days) to look for
16 the best practices, in light of Wyoming’s and PacifiCorp’s circumstances, would
17 be useful. While the OCA has done some research in this area in preparation for
18 the filing of our testimony, additional opportunities to discuss with the parties
19 specific proposals that we may wish to present would be useful.

20

21 **Q. WHAT WOULD BE THE PURPOSE OF ADDING ADDITIONAL**
22 **BALANCED PROVISIONS TO THE PCAM?**

23 A. The OCA believes that Dr. Schmidt defines the proper goals in his book
24 *Performance-Based Ratemaking: Theory and Practice*. At page 17 he states:

25

26

27

28

29

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33

34

1 To summarize, the goals for performance-based ratemaking
2 include:

- 3 • Improve the efficiency and performance of the
4 utility.
- 5 • Improve incentives and remove disincentives for
6 utility cost reduction.
- 7 • Simplify and streamline the regulatory process.
- 8 • Maintain a reasonable opportunity for the utility to
9 not only earn a fair rate of return, but extra profits
10 as determined under the performance-based
11 ratemaking plan.
- 12 • Maintain and improve quality of service.
- 13

14 **Q. PLEASE PROVIDE SOME ILLUSTRATIONS OF THE PROVISIONS**
15 **THAT COULD BE ADDED TO THE PCAM TO MAKE IT MORE**
16 **BALANCED BETWEEN RATEPAYERS AND SHAREHOLDERS.**

17 A. The following is a sampling of the kinds of provisions that could be, and are,
18 being used:

- 19 1. *Rate cap or rate ceiling.* A maximum price that can be charged is
20 established. This level is often established by applying an index
21 factor to the current rate levels. This index factor could be based
22 on some general economic growth factor (such as the Producer
23 Price Index) and frequently is then reduced by a productivity factor
24 to reflect the increased efficiency that is anticipated to occur
25 because of technological or labor efficiencies.
- 26 2. *Rate freezes.* Rates are initially established in a rate proceeding at
27 levels that allow the utility a reasonable opportunity to earn a
28 return on its investment. These rates are then frozen for an agreed-
29 upon (or established) period of time. The utility has an incentive
30 to control costs and/or improve efficiencies so that its profit levels
31 are not eaten away by inflationary factors.
- 32 3. *Earnings sharing.* This method might measure the utility's earned
33 return. If it falls within a specific deadband, nothing happens. If
34 the utility is able to improve its earnings above the deadband, it
35 shares those savings between shareholders and ratepayers. In some

1 instances, decreased earnings levels would prompt an increase in
2 rates, but in a way that does not have ratepayers paying the entirety
3 of the increased costs.

- 4 4. *More meaningful cost sharing deadbands.* This method would
5 incorporate deadbands and cost sharing bands such as those
6 conceptually proposed by Mr. Widmer. However, the band levels
7 would be established so that there was much more incentive built
8 in for the utility to control costs and for the ratepayers to share in
9 cost savings.

10
11 **Q. IS IT IMPORTANT TO IMPLEMENT THESE ADDITIONAL**
12 **PROVISION(S) AS PART OF THE SAME MECHANISM THAT PASSES**
13 **ON NET POWER COST CHANGES, RATHER THAN IMPLEMENTING**
14 **THEM SEPARATELY?**

- 15 A. Yes. They must be kept together in order to maintain the balance that is necessary
16 to keep risk and rewards synchronized with the cost-sharing proposal that has
17 been made. The OCA believes these must be kept together to assure that one is
18 not implemented without the other, and that one is not changed or eliminated
19 without considering the impact on the other.

20
21 **Q. WHY DO YOU BELIEVE THAT THE PROPOSED DEADBANDS AND**
22 **SHARING LEVELS DO NOT REFLECT THE PROPER**
23 **APPORTIONMENT OF RISK AND REWARD BETWEEN RATEPAYERS**
24 **AND SHAREHOLDERS?**

- 25 A. This is best represented with an example using numbers from the Company's
26 most recent rate case. In his original exhibits filed with that rate case, Mr.
27 Widmer shows normalized net power costs of \$557 million and actual net power
28 costs of \$685 million. I'd like to offer an example using those two sets of
29 numbers. In speaking with Mr. Widmer, he has agreed that there would be only a
30 very slight difference in the MWH represented by these two sets of costs, and

1 therefore, for the sake of simplicity, I will use the same denominator to arrive at
2 an actual and normalized cost per total requirements MWH.

3

4 Normalized Net Power Cost = $\$557,467,268 / 75,043,445 \text{ MWH} = \7.43

5 Actual Net Power Cost = $\$685,149,583 / 75,043,445 \text{ MWH} = \9.13

6

7 If the \$7.43 were the base cost, when the actual is measured against it, the
8 difference would be \$1.70 per MWH. This is an increase of 23 percent over the
9 base. If I understand Mr. Widmer's proposal, cost changes at this level would be
10 shared with shareholders being responsible for 5% of the cost increase and
11 ratepayers responsible for 95%. This means that shareholders would have to
12 absorb \$.085 per MWH and ratepayers would have to pay an additional \$1.615
13 per MWH. Or, if the loads stayed constant, shareholders would pay \$6.3 million
14 of the increase and ratepayers would pay \$121 million on a total company basis.
15 On a Wyoming basis, those numbers would be less than \$1 million to
16 shareholders and more than \$18 million to ratepayers. This would be an annual
17 increase larger than any one of the last three rate increases in Wyoming. (At the
18 time this testimony was being written, the current rate decision in Wyoming is
19 still pending.)

20

21 There is no explanation offered by PacifiCorp as to why this sharing level is
22 appropriate and how the deadband determinations were made. The practical
23 effect is that shareholders carry very little risk under the proposal and are
24 substantially better off than they are under the current ratemaking method. Yet, no
25 recognition of this lessened shareholder risk is reflected anywhere in rates.

26

27

28

29

30

31

1 **Q. AS A FINAL AREA OF DISCUSSION, IF THE COMMISSION IS**
2 **CONVINCED BY SUBSTANTIAL EVIDENCE THAT PACIFICORP'S**
3 **PCAM IS THE BEST OPTION AT THIS TIME, AND THAT IT**
4 **PROMOTES THE PUBLIC INTEREST, ARE THERE SOME DETAILS**
5 **OF THE PROPOSAL FOR WHICH YOU WOULD LIKE TO SEE**
6 **CLARIFICATION.**

7 A. Yes, the proposal needs several clarifications and technical enhancements. I will
8 walk through each of these below.

9
10 **Q. WHAT IS YOUR FIRST REQUESTED CLARIFICATION?**

11 A. The Commission should determine the appropriate costs to be included in a semi-
12 automatic rate adjustment mechanism. Currently, the Commission's most
13 common pass-on mechanism is defined in Section 249 of its Procedural Rules and
14 Special Regulations. This rule indicates that only "wholesale utility commodity
15 cost increases and decreases not under this Commission's jurisdiction" are
16 allowed to be included in the expedited regulatory system. While the
17 Commission has taken a somewhat liberal view of the costs that may be included
18 pursuant to this provision, it has limited the costs that can be included. So, the
19 Commission should carefully consider the extent to which it wishes to expand the
20 nature of the costs that can be passed on to customers through an expedited
21 process with more limited regulatory reviews than are normally and traditionally
22 afforded most of the utility's expenditures.

23
24 **Q. DO YOU HAVE AN EXAMPLE OF THE TYPE OF COST THAT YOU**
25 **WISH THE COMMISSION TO CONSIDER EXCLUDING FROM THE**
26 **PCAM?**

27 A. Yes. I question whether demand payments associated with longer-term firm
28 purchases should be included in the PCAM. These payments are often part of a
29 longer-term purchase that is entered into in lieu of a utility constructing its own
30 generating facility that would be available as needed. Since the alternative to
31 these payments would be an addition to rate base, an expenditure that would not

1 be allowed to be passed through to customers without a general rate case, the
2 demand payments arguably warrant similar treatment.

3
4 **Q. HOW SHOULD CONTRACT CUSTOMERS BE TREATED RELATIVE**
5 **TO THE APPLICATION OF THE PCAM?**

6 A. PacifiCorp has indicated its intention to spread the increased net power costs by
7 means of a per kWh charge or credit on all customers, differentiated only by
8 voltage levels. Yet, PacifiCorp has also indicated its intent not to apply any of the
9 increase to contract customers, should there be any in Wyoming.

10
11 The OCA is concerned about PacifiCorp's intent to not share any increase or
12 decrease in net power costs with contract customers. However, we know that the
13 Commission has no ability to modify an existing contract between a customer and
14 a utility. Therefore, I suggest that PacifiCorp be required to absorb the portion of
15 the increase that would otherwise have been assigned to a customer who happens
16 to be taking service pursuant to a non-tariffed rate. In this manner, the contract
17 customer will not be required to pay a rate different from what it agreed to pay,
18 but other customers will also not be required to pay the contract customer's share
19 of the change in costs.

20
21 **Q. DO YOU HAVE A CONCERN ABOUT THE TARIFF LANGUAGE**
22 **SUBMITTED BY PACIFICORP IN ITS PROPOSED TARIFF**
23 **REFLECTING ITS PROPOSED PCAM?**

24 A. Yes. The tariff is vague in describing the nature and the impact of the PCAM on
25 rates. While the proposed tariff does have a placeholder for the individual
26 surcharges and credits that may be implemented over time, it has no description of
27 the process or computations that will be used to derive those credits or surcharges.

28
29 PacifiCorp has frequently tried to compare its proposed PCAM to the cost
30 recovery process described in Sections 249 and 250 of the Commission's

1 Procedural Rules and Special Regulations. Yet, PacifiCorp apparently felt no
2 obligation to comply with section 250(b) that requires:

3 The proposed Commodity Balancing Account tariff applied for by
4 a utility shall include a description of the planned method of
5 calculating the cost increases or decreases of wholesale commodity
6 purchases utilizing an energy unit measurement (Btu, etc.) uniform
7 with its authorized rates, and setting forth as is appropriate general
8 provisions for determinations of volumes, purchase sources
9 including storage, and taxes. . .

10
11 The OCA suggests that the Commission direct PacifiCorp to file tariffs in
12 compliance with its decision, and that the filed tariffs contain an appropriately
13 specific description of the formula to be used in computing annual cost changes.

14
15 **Q. MR. WIDMER OFFERS ON PAGE 11 OF HIS TESTIMONY THAT**
16 **PACIFICORP WILL FILE FINANCIAL EARNINGS STATEMENTS**
17 **WITH “ANY FILING SEEKING RECOVERY OF DEFERRED COSTS**
18 **FROM CUSTOMERS.” WHAT IS YOUR CONCERN WITH THIS**
19 **OFFER?**

20 A. The statement has some room for interpretation and should be clarified up-front.
21 The OCA would prefer to see a financial statement annually rather than at an
22 undetermined frequency. My understanding is that it would not be overly
23 burdensome for PacifiCorp to provide an annual financial statement, since it has
24 to prepare periodic financial statements for several other states, and the Wyoming
25 statement could be easily prepared in conjunction with filings pursuant to other
26 states’ requirements.

27
28 Additionally, in the past, the OCA has run into some instances where financial
29 statements were filed by utilities with pass-ons but when those statements were
30 relied upon to make financial recommendations, controversy arose as to what
31 those statements actually showed. Therefore, there should be an understanding
32 that the financial statements may be relied upon by the Commission to fairly
33 represent the Company’s best computation of its current earnings situation.

34

1 **Q. WHAT IS THE NEXT ISSUE FOR WHICH YOU WISH**
2 **CLARIFICATION?**

3 A. PacifiCorp has proposed two filings during the course of the year: one filing to
4 reflect its best estimate of upcoming annual, estimated net power costs and one to
5 set the amortization of the difference between the costs collected through rates
6 and actual costs. It seems unnecessary to have these in separate filings that are
7 made months apart. The OCA would prefer one annual filing.

8

9 **Q. ARE YOU ALSO CONCERNED THAT PACIFICORP HAS INDICATED**
10 **ITS INTENTION OF ONLY PAYING SIX PERCENT INTEREST ON**
11 **OVERCOLLECTIONS ASSOCIATED WITH THE PCAM?**

12 A. Yes. The OCA recommends that interest on overcollections be paid at a level
13 equal to PacifiCorp's Wyoming authorized rate of return. The overcollection
14 provides PacifiCorp funds that can be invested in many things, including
15 additional PacifiCorp plant and equipment. Once put into rate base, PacifiCorp
16 would have the opportunity to earn on that plant at the overall authorized rate of
17 return.

18

19 If PacifiCorp were permitted to pay interest at a low, fixed rate on these
20 overcollected funds – funds that really belong to the ratepayers – it could benefit
21 from overestimating costs and overcharging customers. This would occur
22 because it could earn at 8 or 9 percent, while being required to pay customers six
23 percent. This is inappropriate and should not be permitted as part of the PCAM.

24

25 **Q. IS THE OCA CONCERNED ABOUT THE WAY THAT PACIFICORP**
26 **DEFINES HOW IT WILL COMPUTE ACTUAL NET POWER COSTS?**

27 A. Yes. At page 7 of his testimony, Mr. Widmer states:

28 Adjusted actual NPC are equal to actual NPC adjusted to remove
29 prior period adjustments recorded during the deferral period and to
30 include Commission adopted adjustments from the most recent
31 general rate case for events that were under the Company's
32 control.

33

1 I see the potential for many interpretation issues relative to “events that were
2 under the Company’s control.” For example, in recent cases before the
3 Commission, parties have argued that the Western Area Power Authority
4 (WAPA) wholesale power contract revenues should be assumed to be greater than
5 they actually are for ratemaking purposes, based on the lack of an inflationary
6 clause in an extremely long contract. If the Commission adopts this adjustment
7 (noting that there is no decision at the time of this writing), it might be unclear
8 whether this would be considered an event inside or outside of the
9 Company’s control. It would be better to simply incorporate all Commission
10 adopted adjustments into the annual actual net power cost computation.

11
12 **Q. ARE YOU ALSO CONCERNED ABOUT THE LIMITATIONS THAT**
13 **PACIFICORP PROPOSES TO IMPOSE ON THE PRUDENCE REVIEWS**
14 **THAT CAN BE DONE IN ASSOCIATION WITH THE PACIFICORP**
15 **ANNUAL PCAM FILINGS?**

16 A. Yes, this is very troubling. Specifically, Mr. Widmer proposes that costs and
17 revenues related to existing contracts and resources that have previously been
18 included in rates be excluded from any further prudence review. This presents a
19 great hazard to ratepayers and to the OCA, who has limited resources but broad
20 responsibilities. There appears to be an underlying assumption in proposing this
21 limitation that every new cost, asset, transaction, and contract is reviewed in the
22 case following its appearance or creation. If this were the case, it would be more
23 reasonable to request that the review be done initially and not revisited case after
24 case. But, the initial premise that new costs are fully reviewed upon their first
25 appearance is not necessarily true. Costs are reviewed on a selective basis, as the
26 interest in a particular item waxes and wanes, and as time permits. If parties did
27 not have the full opportunity to raise issues on matters as those issues rose in
28 importance and interest, or as new information about the particular transaction
29 arose, parties would be unduly prejudiced and the public interest would be
30 compromised.

31

1 The Commission must not limit parties' ability to raise issues in cases. In
2 exchange, the Commission should take some comfort in the fact that because
3 parties' time and money is limited, it is in no one's interest to waste that time and
4 money by rehashing issues that have already been fully considered and decided.
5

6 **Q. WHAT IS YOUR LAST RECOMMENDATION TO THE COMMISSION?**

7 A. In recent PacifiCorp rate cases and cost recovery cases, there has been a great
8 deal of discussion about the appropriate costs and assumptions to be included in
9 the GRID model which is the latest tool used by PacifiCorp to determine
10 normalized power costs. In the currently pending rate case, Dr. Ula, a public
11 witness in the case, raised questions about the appropriateness of PacifiCorp's
12 coal costs. If PacifiCorp were to have a PCAM authorized, the appropriateness of
13 the coal costs would be an appropriate topic both in terms of setting the
14 normalized baseline net power cost and in terms of measuring the actual net
15 power costs to be shared between ratepayers and shareholders.
16

17 As the Commission ponders the complexities of dealing with this and the other
18 GRID modeling and input controversies, on an annual basis, it may wish to
19 consider one additional fact related to the computation. In the Scottish Power
20 merger docket stipulation between the Company and the Consumer Advocate
21 Staff (Docket No. 20000-EA-98-141), item 24 states:

22 Where a market for goods or services or assets exists,
23 PacifiCorp/Scottish Power shall allow the Commission to assert
24 the more advantageous of cost or market pricing standard for
25 affiliate transactions for ratemaking purposes.
26

27 Parties may begin raising this issue and asking to make an adjustment to coal
28 costs in order to reflect market prices rather than contract costs. The Commission
29 should not limit the parties' ability to raise such issues as PacifiCorp requests.
30
31
32
33

1 **Q. WHAT IS YOUR CONCLUDING COMMENT ON THIS ENTIRE**
2 **PROPOSAL?**

3 A. While the Commission may be tempted to simplify the regulatory mechanism for
4 ease of administration and for understandability reasons, such a temptation should
5 be resisted. As pointed out by the OCA, simplification would likely come at the
6 expense of ratepayers and the public interest. The only way to fix the PacifiCorp
7 proposal and to make it acceptable and reasonable is to add a number of
8 provisions and clarifications.. While the result may be a complex, or even very
9 complex mechanism, sometimes, as in the case of a very complex operation like
10 PacifiCorp's, that is what is required to make a regulatory system that is balanced
11 and fair to all interested parties.

12
13 **Q. DOES THIS COMPLETE YOUR DIRECT PREFILED TESTIMONY?**

14 A. Yes.