



1 **Q. Please State your name, business address and position with PacifiCorp (“the**  
2 **Company.”)**

3 A. My name is David L. Taylor. My business address is 825 NE Multnomah Street,  
4 Suite 800, Portland, Oregon 97232. I am employed by PacifiCorp as Director,  
5 Revenue Requirement and Cost of Service.

6 **Qualifications**

7 **Q. Please summarize your education and business experience.**

8 A. I received a Bachelor of Science degree in Accounting from Weber State College  
9 in 1979 and a M.B.A. from Brigham Young University in 1986. I have been  
10 employed by PacifiCorp since the merger with Utah Power in 1989 (“Merger”).  
11 Prior to the Merger I was employed by Utah Power, beginning in 1979. At the  
12 Company I have worked in the Accounting, Budgeting, and Pricing and  
13 Regulatory areas. From 1987 to the present I have held several supervision and  
14 management positions in Pricing and Regulation.

15 **Q. Have you appeared as a witness in previous regulatory proceedings?**

16 A. Yes. I have testified on numerous occasions in California, Idaho, Montana,  
17 Oregon, Utah, Washington and Wyoming.

18 **Purpose**

19 **Q. What is the purpose of your direct testimony in these proceedings?**

20 A. My direct testimony covers four areas. First, it provides the basis for the  
21 allocation procedures used in the Company’s proposed inter-jurisdictional cost  
22 allocation method, which was identified as the “MSP Solution” in Ms. Kelly’s  
23 direct testimony. This portion of my direct testimony discusses the classification

1 and allocation of generation and transmission costs, the treatment of non-tariff  
2 Special Contracts and the treatment of the Hydro and Coal Endowments and  
3 certain new baseload Resources. Second, my testimony considers the  
4 implications of disproportionate load growth in one State on the revenue  
5 requirements of other States. Third, my testimony estimates the impact of the  
6 MSP Solution on the overall revenue requirements in each State. Finally, my  
7 direct testimony also presents PacifiCorp's functionalized Class Cost of Service  
8 Study for Washington based on the test period ending March 2003.

9 **MSP Solution Allocation Procedures**

10 **Q. Please summarize the procedures that the Company proposes to follow in**  
11 **allocating the costs of generation Resources.**

12 A. The allocation of a utility's costs employs a three-step process generally referred  
13 to as "functionalization", "classification", and "allocation". The use of these three  
14 steps recognizes the way a utility provides electrical service and attempts to  
15 assign cost responsibility to the groups of customers for whom those costs were  
16 incurred.

17 Functionalization, the process of separating expenses and rate base items  
18 between the generation, transmission, and distribution functions, is generally not  
19 at issue in MSP.

20 Classification is the process of separating costs between those which are  
21 Demand-Related, Energy-Related, or Customer-Related. Demand-Related costs  
22 are the capital and other fixed costs incurred by the Company in order to be  
23 prepared to meet the maximum Demand imposed on generating units,

1 transmission lines, and distribution facilities. Energy-Related costs are costs  
2 (such as fuel costs) that vary with the amount of Energy actually generated plus  
3 any portion of Fixed Costs that have been classified as Energy-Related.

4 Customer-Related costs are those that are primarily driven by the number of  
5 customers served.

6 Allocation is the process of assigning Demand, Energy, and Customer-  
7 Related costs among States or customer groups. This is achieved by the use of  
8 allocation factors that specify each State's share of a particular cost driver such as  
9 system peak demand, energy consumed, or number of customers. The appropriate  
10 allocation factor determines each State's share of cost.

11 With the exceptions that I will describe later, the MSP Solution is an  
12 integrated system methodology pursuant to which customer loads are deemed to  
13 be served from a common Resource portfolio. The MSP Solution only deals with  
14 the allocation of costs among States. The procedures for allocation of costs  
15 among customer classes will continue to be determined independently by each  
16 State.

17 **Q. How is your testimony concerning the allocation procedures relied upon in**  
18 **the MSP Solution organized?**

19 A. First, I will discuss the Company's analysis and conclusions on general  
20 classification and allocation procedures. Then, I will detail the specific  
21 classification and allocation procedures for each type of Resource identified in the  
22 MSP Solution. Appendix A to the MSP Solution set forth in Exhibit  
23 No. \_\_\_ (ALK-2) is a list of defined terms. For purposes of greater clarity and

1 consistency, when I capitalize terms in my direct testimony, and do not otherwise  
2 define them, it is intended that those terms have the same meaning as provided for  
3 in Appendix A to the MSP Solution.

#### 4 **Classification of Generation Costs**

5 **Q. Does the Company propose to continue to classify the majority of generation**  
6 **fixed costs and Wholesale Contracts as 75 percent Demand-Related and 25**  
7 **percent Energy-Related?**

8 A. Yes. With the exception of Simple-cycle Combustion Turbines (SCCTs),  
9 PacifiCorp found no compelling reason to change from the currently employed 75  
10 percent Demand/25 percent Energy classification of generation fixed costs. We  
11 also propose to continue the practice of allocating Energy-Related Costs based  
12 upon energy usage. Commissions have generally found that these methods have a  
13 reasonable basis in cost causation and changing them would have unwarranted  
14 impacts on State revenue requirements.

15 A discussion paper on the topic of Classification and Allocation of  
16 Generation Fixed Costs is presented as Exhibit No.\_\_\_\_(DLT-2). The paper  
17 reviews some of the classification and allocation history at PacifiCorp and its  
18 predecessor companies. It also draws from the 1992 NARUC *Electric Utility*  
19 *Cost Allocation Manual*, which catalogues a number of classification methods  
20 commonly employed by utilities.

21 It is not uncommon to classify all Fixed Costs as Demand-Related since,  
22 in general, system capacity must be sufficient to meet maximum demand and thus  
23 costs are said not to vary with respect to energy output. On the other hand,

1 engineering analyses employing system reliability criteria in system planning  
2 might reveal that the Fixed Costs of generation plant production are both Demand  
3 and Energy-Related, as would analyses showing that peak demand should be met  
4 with peaking plant while additional energy loads should be met with intermediate  
5 and baseload plant. This is said to justify the inclusion of some portion of energy  
6 in the allocation factor to be applied to production plant costs.

7 Exhibit No. \_\_\_(DLT-2) applied the methods discussed in the NARUC  
8 *Manual* to PacifiCorp's State peak and energy load data and produced a range of  
9 results. Demand-Related production costs could vary from 100 percent, to a low  
10 end of 27 percent using the "Average and Excess Demand" method. The  
11 Company also surveyed a number of electric utilities serving in other states,  
12 finding wide classification differences among them.

13 The choice of the 75 percent Demand/25 percent Energy classification for  
14 generation and transmission plant was the final allocation decision made by the  
15 PacifiCorp Inter-Jurisdictional Taskforce on Allocations ("PITA") after the  
16 Merger. The PITA analysis also indicated that a wide range of demand and  
17 energy classification methods could be supported on a technical basis. The  
18 demand/energy classification was the means ultimately used to balance the  
19 sharing of merger benefits among all the States. The 75 percent Demand/25  
20 percent Energy classification method was selected because it produced an overall  
21 cost allocation result that was acceptable to all the States.

22 Because no clearly superior demand/energy classification split has  
23 emerged from analyses conducted during the Multi-State Process ("MSP"), and

1 because the 75 percent Demand/25 percent Energy classification of generation  
2 Fixed Costs currently used by PacifiCorp falls in the middle of the range of  
3 reasonable approaches, we propose to continue to use it for all System and  
4 Regional Resources and most Seasonal Resources. System and Regional  
5 Resources are primarily baseload plants and purchases. The Cholla Unit IV plant,  
6 which is identified as a Seasonal Resource, is also a baseload plant and will be  
7 classified consistent with the System and Regional Resources.

8 However, PacifiCorp does propose to change the classification for Simple-  
9 cycle Combustion Turbines to 100 percent Demand-Related.

10 **Q. Why does PacifiCorp propose to classify the cost of SCCTs differently from**  
11 **the remainder of the Company's Resources?**

12 A. SCCTs are typically peaking Resources that are used differently from base load  
13 Resources, so it is reasonable to employ a classification method that better  
14 matches how customers benefit from their use. One of the justifications for  
15 classifying the fixed costs of baseload plants as both Demand and Energy-Related  
16 is to recognize their design capability to meet both peak demand and to generate  
17 lower cost energy all hours of the day and during all seasons of the year. Because  
18 SCCTs are designed and operated to run during peak-load periods, rather than  
19 produce sustained, low cost energy, we propose to classify their Fixed Costs as  
20 100 percent Demand-Related.

1 **Allocation of Generation Plant**

2 **Q. How does the Company propose to allocate the Demand-Related component**  
3 **of generation costs?**

4 A. As with the issue of the demand/energy classification, the Company found no  
5 compelling evidence to support a change from the current 12 Coincident Peak  
6 (“12 CP”) allocation factor for the demand component of System and Regional  
7 Resources. We did, however, determine that certain Resources, identified as  
8 “Seasonal Resources,” were acquired and dispatched to meet customer needs  
9 during either the winter or summer periods. To match the cost of these Resources  
10 with their use, costs are apportioned across the months of the year consistent with  
11 their dispatch. I will discuss this in greater detail later in my testimony as I  
12 review each Resource type.

13 **Q. How did the Company decide to use a 12 CP method to allocate the demand**  
14 **component of System and Regional Resources?**

15 A. Since the time of the Merger, PacifiCorp’s Demand-Related Costs of generation  
16 Resources have been allocated using the 12 CP Factor, pursuant to which all  
17 months of the year are deemed to play an equal role in Demand-Related cost  
18 causation. To determine if a smaller subset of monthly peaks might form a better  
19 basis for Demand-Related Cost allocation, PacifiCorp revisited the stress factor  
20 analysis that was employed at the time of the Merger.

21 **Q. What is stress factor analysis?**

22 A. Stress factor analysis is a tool used to identify particular months for inclusion in  
23 the capacity allocation factor by examining, month by month, the key elements



1 that stress the ability of the system to meet its peak load requirements and  
2 therefore drive the need for investment in new capacity. PacifiCorp examined  
3 monthly historical and forecast data for three specific stress factors: a) monthly  
4 retail peak demand, b) probability of loads in any hour to contribute to the system  
5 peak, and c) the cost to bring the reserve margin to 15 percent.

6 **Q. Please briefly explain the basis for each of these stress factors and how it is**  
7 **calculated.**

8 A. Monthly retail peak, also referred to as the monthly Coincident Peak, is one of the  
9 most common stress factors. It is the simplest to calculate and perhaps the easiest  
10 to understand. It is single highest combined demand measurement of all  
11 PacifiCorp retail customers during each month. The Company needs enough  
12 available generating capacity to meet this level of load. Months with higher peak  
13 loads are viewed to place more stress on the system than months with lower peak  
14 loads.

15 The probability of contribution to the system peak indicates the number of  
16 hours in each month with loads that exceed a threshold demand level. The  
17 criterion for our analysis was the average available energy from PacifiCorp's  
18 owned and long-term purchased resources divided by the maximum peak capacity  
19 of those same resources, or approximately 83 percent. If the load in any hour of  
20 the year exceeds 83 percent of the annual system peak it is considered to  
21 contribute to the system peak. Months where more hours contribute to the system  
22 peak are considered to place more stress on the system than months where fewer  
23 hours contribute to the peak.

1           The cost to bring the reserve margin to 15 percent identifies months where  
2           the Company's owned plus long-term purchased resources are insufficient to meet  
3           the reserve adjusted peak load and captures the magnitude of that shortfall.  
4           Months where the cost to achieve the reserve margin is greater are considered to  
5           be more stressful on the system than months where the cost is less, or even zero.  
6           The cost is calculated by subtracting the available generating capacity from the  
7           reserve adjusted monthly peak load, or peak load plus 15 percent. When this  
8           value is positive, it is multiplied by the monthly cost of capacity. For our  
9           purposes, the monthly capacity cost of a simple cycle combustion turbine was  
10          used.

11   **Q.    What did the stress factor analysis indicate?**

12   A    To enable a common comparison between the three stress factors and to make  
13          comparisons between months of a given year and between different years several  
14          techniques were used. A method, termed "rationalizing", where the peak demand,  
15          or other measured value, of a given month is stated as a percentage of the  
16          maximum measurement for the year, seemed to be the favored approach.

17          Exhibit No. \_\_\_(DLT-3) summarizes the results of the stress factor  
18          analysis for the forecast years 2004 through 2008. The monthly-rationalized  
19          percents for each stress factor are shown in columns (A) through (C). Column  
20          (D) shows the simple average of the three factors and column (E) shows a  
21          weighted average with the monthly peak value given double weight.

22          As shown in column (A), the monthly retail peak is generally the greatest  
23          in July or August. The peaks for all months of the year, however, are within 80

1 percent of the annual peak with eight months of the year, June through September  
2 and November through February, within 90 percent of the annual peak. Only the  
3 April peak is less than 85 percent of the annual peak.

4 The probability of contribution to system peak is summarized in column  
5 (B). While the probability of summer hours contributing to the peak is the  
6 greatest, the analysis also shows strong probabilities during the winter months. It  
7 also suggests that, with the exception of April, there are hours in all months of the  
8 year that contribute to the system peak.

9 The analysis summarized in column (C) indicates that the cost to bring  
10 reserve margin to 15 percent is again greater in the summer with the winter costs  
11 only about half of that in the summer.

12 The stress factor analyses suggest that winter and summer loads may be  
13 more significant Demand-Related cost drivers than spring and fall loads. We  
14 have addressed this by segregating Seasonal Resources from other Resources. As  
15 mentioned earlier, and as will be discussed in greater detail later in my testimony,  
16 the costs of Seasonal Resources will be assigned to the months those Resources  
17 are dispatched to meet retail load. The seasonal weighting will assign a larger  
18 portion of the Demand-Related costs to the summer and winter months. With this  
19 adjustment for Seasonal Resources, the continued use of the 12 CP Factor for the  
20 remaining Resources appears even more reasonable.

21 **Q. How does the 12 CP Factor work?**

22 A. The 12 CP Factor determines the proportional share of annual Demand-Related  
23 costs that are allocated to each State. For each month of the year, the Coincident

1 Peak, or the hour during which the combined demand of all PacifiCorp retail  
2 customers is the greatest, is identified. For that hour, each State's contribution to  
3 the Coincident Peak, the combined demand of all retail customers in that State, is  
4 measured in megawatts. Each State's contributions to the twelve monthly system  
5 peaks are summed to establish the State's 12 CP measurement. The 12 CP Factor  
6 is calculated by dividing each State's 12 CP by the sum of the twelve monthly  
7 total system Coincident Peaks, or in the case of Regional Resources by the  
8 aggregate sum of the twelve monthly Coincident Peaks of the participating States.

9 **Q. How is the process different for Seasonal Resources?**

10 A. For Seasonal Resources, the process is very similar. The only difference is that  
11 prior to summing the twelve monthly Coincident Peaks, each monthly CP  
12 measurement is weighted by the monthly portion of the total annual energy  
13 generated by the Seasonal Resource. For example, if 30 percent of the annual  
14 generation of a particular Seasonal Resource occurs in July, the monthly  
15 Coincident Peak for July would be weighted by 30 percent in the calculation of  
16 the allocation factor. This, in essence, allocates 30 percent of the Demand-  
17 Related Cost for that Resource among States based upon their contribution to the  
18 July Coincident Peak.

19 **Q. Why does PacifiCorp propose to allocate the cost of Seasonal Resources**  
20 **differently from the remainder of its Resources?**

21 A. Seasonal Resources are designed to be used more intensively at certain times of  
22 year. The proposed allocation method captures this aspect of cost causation. The  
23 weighted CP method allocates the costs of Seasonal Resources more heavily to

1 States that contribute most to system peaks in months in which the Resource  
2 operates.

3 **Q. How is the hour of system peak for each month determined?**

4 A. In the case of an historical test period, the hour of system peak is based on  
5 metered load data. For each hour of the month, all inputs into the system such as  
6 Company owned generation, purchases or interchanges are measured. From that  
7 measurement, all deliveries outside the system or to non-retail customers are  
8 deducted to arrive at total retail load. The Coincident Peak is the hour of each  
9 month during which the combined demand of all retail customers is the greatest.

10 Each State's contribution to hourly loads is determined in essentially the  
11 same way. Each State's hourly load consists of the Company owned generation  
12 within that State, purchases or interchanges delivered into the State, plus metered  
13 flows of energy into the State from other parts of the PacifiCorp system. From  
14 that measurement, metered energy flows out of the State and deliveries to non-  
15 retail customers are deducted to arrive at that State's retail load.

16 In the case of a forecast test period, the system Coincident Peak and each  
17 State's contribution to that peak are forecasted along with retail Energy usage.

### 18 **Allocation of Energy Costs**

19 **Q. How does the Company propose to allocate fuel and other Energy-Related**  
20 **costs?**

21 A. For System and Regional Resources, fuel and other Energy-Related Costs are  
22 allocated using each participating State's share of annual system energy usage.  
23 For each type of Seasonal Resource, other than Seasonal Contracts, Energy-

1 Related Costs are allocated using weighted monthly energy usage. Similar to the  
2 weighting of Demand-Related costs, each State's monthly energy usage is  
3 weighted by that month's portion of annual energy generation for the particular  
4 Resource. The annual fuel costs for that Resource are then allocated using its  
5 seasonally weighted energy factor.

#### 6 **Cost Allocation for Regional Resources**

7 **Q. Are the costs of Regional Resources allocated differently than the costs of**  
8 **System Resources?**

9 A. Yes. Regional Resources consist of: a) the Hydro Endowment, b) the Coal  
10 Endowment, and c) the First Major New Coal Resource. Costs of Regional  
11 Resources are, in the first instance, assigned to fewer than all States, depending  
12 upon the nature of the Regional Resource. Once this assignment is made, costs  
13 are allocated among the assigned States using the same methods that apply to  
14 System Resources.

#### 15 **Hydro-Electric Resources**

16 **Q. Please explain how the costs of Hydro-Electric Resources are assigned and**  
17 **allocated.**

18 A. The MSP Solution assigns the existing and future investment and operating costs  
19 of Hydro-Electric Resources, including those associated with relicensing, to the  
20 former Pacific Power States. Participating States are then allocated their  
21 proportional share of the Hydro-Electric Resource costs using the Divisional 75  
22 percent 12 CP / 25 percent annual Energy allocation method, or DGP (Divisional  
23 Generation - Pacific) factor. The DGP factor is calculated using the classification

1 and allocation procedures described above for System and Regional Resources.

2 However, because this is a Regional Resource, only the loads of the former

3 Pacific Power States are included in calculating the allocation factors.

#### 4 **Huntington Resource**

5 **Q. Please explain how the costs of the Huntington Resource are assigned and**  
6 **allocated.**

7 A. The MSP Solution assigns the existing and future investment and operating costs  
8 of the Huntington Resource, including those associated with clean air initiatives,  
9 to the former Utah Power States. Participating States are then allocated their  
10 proportional share of the Huntington Resource Fixed Costs using the Divisional  
11 75 percent 12 CP / 25 percent annual Energy allocation method, or DGU  
12 (Divisional Generation - Utah) factor. The DGU factor is calculated using the  
13 classification and allocation procedures described above for System and Regional  
14 Resources. However, because this is a Regional Resource, only the loads for the  
15 former Utah Power States are included in calculating the allocation factors. The  
16 former Utah Power States are also allocated their proportional share of the  
17 Huntington Resource Energy-Related Costs using the Divisional Energy, or DEU  
18 (Divisional Energy - Utah) factor.

#### 19 **First New Major Coal Resource**

20 **Q. How does the proposal to permit Oregon to “opt-out” of the First New Major**  
21 **Coal Resource affect the allocation of generation costs?**

22 A. If the Oregon Commission elects this option, costs of the First New Major Coal  
23 Resource would be assigned to the remaining States. The costs of the Resource

1 would then be allocated among those remaining States using the classification and  
2 allocation procedures described above for System Resources. Fixed costs will be  
3 classified as 75 percent Demand-Related and 25 percent Energy-Related with the  
4 demand component allocated using the 12 CP Factor. Energy costs will be  
5 allocated using the Annual Energy Factor.

6 Also, in the event Oregon chooses not to participate in the First New  
7 Major Coal Resource, an alternate baseload Resource of equivalent vintage and  
8 size to Oregon's proportional share of the coal Resource would be assigned to  
9 Oregon in its place. Otherwise, Oregon would be avoiding the cost associated  
10 with a new, undepreciated Resource and replacing it with a disproportionate share  
11 of lower-cost resources from the largely depreciated embedded portfolio (which  
12 consists largely of coal-fired Resources). Assigning Oregon the cost of an  
13 alternate non-coal-fired matching Resource matches more closely the economic  
14 effects of Oregon's policy decision.

15 In the event Oregon chooses not to opt out of participation in the First  
16 Major New Coal Resource, costs of the Resource would be treated as a System  
17 Resource.

#### 18 **Cost Allocation for Seasonal Resources**

19 **Q. Are the costs of Seasonal Resources allocated differently than the costs of**  
20 **System Resources?**

21 A. Yes. Somewhat different procedures are used for simple-cycle combustion  
22 turbines, Seasonal Contracts and the costs of Cholla Unit IV.



1 **Simple Cycle Combustion Turbines**

2 **Q. How does the Company propose to classify and allocate the costs of Simple-**  
3 **Cycle Combustion Turbines?**

4 A. As described earlier in my testimony, the fixed costs of SCCTs are classified as  
5 100 percent Demand-Related. Both the Demand-Related and Energy-Related  
6 Costs are then assigned to the individual months of the year on the proportional  
7 basis of the annual dispatch hours for the given month in which those resources  
8 are dispatched to meet retail load. Mr. Duvall describes how these values are  
9 determined. The aggregate Demand-Related Costs of the turbines are allocated to  
10 States using the Simple-Cycle Combustion Turbine dispatch weighted 12 CP  
11 (Seasonal System Capacity Combustion Turbine or SSCCT) allocation factor and  
12 the Energy-Related Costs are allocated using the Simple-cycle Combustion  
13 Turbine dispatch weighted Energy (Seasonal System Energy Combustion Turbine  
14 or SSECT) allocation factor. This process was described earlier in my testimony.

15 Because existing SCCTs are dispatched more heavily during the summer  
16 months, the majority of their costs are allocated using summer loads.

17 **Seasonal Contracts**

18 **Q. Does PacifiCorp propose to allocate the cost of Seasonal Contracts in the**  
19 **same way as SCCTs?**

20 A. Generally, yes. As with the Simple-Cycle Combustion Turbines, the cost of  
21 Seasonal Contracts will be allocated on a weighted monthly basis according to  
22 their monthly delivered megawatt hours. Because some of the contracts do not  
23 have explicit Demand and Energy components, however, the entire contracts will

1 be classified as 75 percent Demand- and 25 percent Energy-Related and allocated  
2 to States using the seasonally weighted (Seasonal System Generation Purchases or  
3 SSGP) allocation factor.

4 **Cholla Unit IV**

5 **Q. Are there any other Resources that are more heavily used in one season of**  
6 **the year?**

7 A. Yes. The Cholla plant is considered a winter Seasonal Resource. Although the  
8 Cholla Unit IV is operated all year except for times of required maintenance, a  
9 substantial portion of the summer output is delivered to Arizona Public Service  
10 Company (“APS”) and an equivalent amount of capacity and energy is returned to  
11 PacifiCorp during the winter months.

12 **Q. How are the costs of the Cholla Unit IV to be allocated under the MSP**  
13 **Solution?**

14 A. The costs of the Cholla plant are allocated using a similar monthly weighting  
15 methodology as used for SCCTs with an adjustment for the megawatt hours  
16 delivered to and received from APS. Both the demand and energy components of  
17 plant costs are assigned to months on the basis of monthly megawatt hours  
18 dispatched from Cholla plus megawatt hours received from APS less megawatt  
19 hours delivered to APS. This assigns the majority of the Cholla costs to five  
20 winter months, October through February.

21 Because Cholla is a baseload plant, fixed costs are classified as 75 percent  
22 Demand/25 percent Energy. The Fixed Costs are allocated using the Seasonal  
23 System Generation Cholla (SSGCH) allocation factor and fuel costs are allocated

1 using the Seasonal System Energy Cholla (SSECH) allocation factor.

2 **System Resources**

3 **Q. What is the allocation procedure for the remaining System Resources?**

4 A. The Fixed Costs of System Resources are allocated using the 75 percent Demand,  
5 25 percent Energy 12 CP (System Generation or SG) allocation factor. Variable  
6 Costs for System Resources are allocated using the Annual Energy (System  
7 Energy or SG) allocation factor. The basis for these allocation factors and a  
8 description of how they are calculated were discussed earlier in my testimony.

9 **Transmission Costs**

10 **Q. How does the MSP Solution propose to classify and allocate transmission**  
11 **costs?**

12 A. Costs associated with transmission assets and firm wheeling expense are  
13 classified as 75 percent Demand/25 percent Energy-Related and allocated using  
14 the SG allocation factor. Non-firm wheeling expense and revenues are classified  
15 as Energy-Related and allocated among the States based upon the SE Factor.

16 **Q. Would this allocation change with the implementation of an RTO?**

17 A. In the future, in the event PacifiCorp becomes a participant in an RTO, charges  
18 from the RTO would be allocated among the States based upon the same billing  
19 determinants relied upon by the FERC in setting the RTO's rates.

20 **Q. What would be the revenue requirement allocation implication if FERC**  
21 **requires that certain current transmission assets be refunctionalized?**

22 A. Those that are refunctionalized as generation assets will be allocated consistent  
23 with the allocation of the fixed costs of the Resource with which they are

1 associated. Those refunctionalized as distribution assets will be direct assigned to  
2 the State where they are physically located.

3 **Distribution Costs**

4 **Q. Does the MSP Solution propose any change to the allocation of distribution**  
5 **costs?**

6 A. No. Distribution costs are all directly assigned to individual States and no  
7 jurisdictional allocation is required.

8 **Administrative and General (A&G) Costs**

9 **Q. With the change in the allocation of some of the generation plant costs, have**  
10 **you looked at the impact of these new allocation procedures on the sharing of**  
11 **A&G and other infrastructure costs?**

12 A. Yes, and the impacts appear to be minimal. Historically PacifiCorp has allocated  
13 the bulk of A&G expenses, the costs of General Plant and Intangible Plant, and  
14 other common costs using a System Overhead (SO) factor. The SO factor is  
15 calculated using each State's proportional share of allocated and assigned plant  
16 investment. With a change in the allocation for some of the generation assets,  
17 there will be a corresponding shift in the allocation of these common costs. To  
18 test whether that shift was significant enough to warrant development of a new  
19 allocation procedure, the Company compared the allocation of all costs using the  
20 SO factor under the proposed method with the allocation of those same costs  
21 under the rolled-in allocation method. The impact of the change in the SO factor  
22 was approximately plus or minus one percent of system overhead costs and less  
23 than 0.15 percent of total State revenue requirements. We did not consider this

1 impact to be large enough to warrant a change in methodology for the allocation  
2 of system overhead costs.

3 **Special Contracts**

4 **Q. What is the Company's proposal regarding the treatment of Special**  
5 **Contracts?**

6 A. As described in the direct testimony of Ms. Kelly, the Company proposes that if a  
7 Commission makes a decision for reasons of local or State interest that increases  
8 costs to customers in other States, the costs of the decision should be borne  
9 entirely within the State making the decision. As applied to Special Contracts, the  
10 cost of serving contract customer loads, and their State approved retail service  
11 revenues, will be included in the local State's revenue requirement on the same  
12 basis as would apply to the cost of serving any other retail customer. Any  
13 payments made (or discounts provided) for the Customer Ancillary Service  
14 Contract attributes, such as operating reserves, system integrity interruption, or  
15 economic curtailment, will be treated as a Resource acquisition by the Company  
16 and included as a purchased power costs allocated among all States. If a buy-  
17 through option is provided with economic curtailment, both the cost and the  
18 revenue associated with the buy- through will be assigned situs to the host  
19 jurisdiction. This removes the effect of the buy-through from non-host  
20 jurisdictions and from all other customers in the host jurisdiction.

21 As with the establishment of retail tariff prices, the Commission with  
22 jurisdiction over a Special Contract will, within the context of the State revenue  
23 requirement, have authority to establish the retail service price for the contract.

1 This includes the application of State-specific public policy preferences that may  
2 allow Commissions to consider other issues, in addition to costs, when setting  
3 retail prices.

4 Exhibit No. \_\_\_(DLT-4) shows an example of the impact of the proposed  
5 treatment of Special Contracts on State revenue requirements. This example  
6 assumes a three-jurisdiction system. Jurisdictions two and three each have  
7 Special Contracts and Jurisdiction one does not. Jurisdictional loads and potential  
8 resources are shown on lines 1 through 6. Allocation factors based on total State  
9 loads are shown on lines 8 through 11. The “No Ancillary Service Contracts”  
10 example, lines 16 through 23 show the resource cost of service and associated  
11 revenues assuming no ancillary services are acquired from the two Special  
12 Contracts. The second example, lines 28 through 48 show the resource cost of  
13 service and associated revenues assuming there are ancillary service components  
14 to each of the contracts.

15 In the “With Ancillary Service Contracts” example, Contract A has retail  
16 service revenue of \$40 million and receives a \$4 million discount for providing  
17 100 MW of operating reserves. Contract B has retail service revenue of \$20  
18 million and receives a \$3 million discount for allowing 75 MW of economic  
19 curtailment for up to 500 hours per year.

20 The \$4 million discount, or payment, for reserves is identified as a  
21 Resource acquisition and is shown on line 41 as part of the cost of service.  
22 Likewise the \$3 million discount, or payment, for economic curtailment is also  
23 identified as a Resource acquisition and shown on lines 42 and 43. Because these

1 Resources are obtained from the two customers rather than other sources, the  
2 Energy-Related and Demand-Related costs, shown on lines 39 and 40, are \$7  
3 million less than in the first example, lines 17 and 18, where there were no  
4 ancillary services contracts. Comparing line 19 with line 44, total cost of service,  
5 both total system and by jurisdiction, are equal whether or not the ancillary  
6 services are acquired from the contract customers.

7 As with total cost of service, jurisdictional revenues are also unchanged.  
8 The \$40 million associated Contract A and the \$20 million associated with  
9 Contract B continue to be identified as jurisdictional revenues and the revenues to  
10 be collected from all other customers, as shown on lines 23 and 48, remain  
11 unchanged.

## 12 **Load Growth**

13 **Q. You testified that the MSP Solution allocates costs dynamically and, with the**  
14 **exceptions identified above, all States share in the cost of new Resources.**  
15 **Does this provision cause slow-growing States to subsidize fast-growing**  
16 **States?**

17 A. As Mr. Duvall has testified, we do not believe this occurs to a material degree.  
18 During the MSP, PacifiCorp prepared an example that identified the implications  
19 of disproportionate load growth in one State and the Resources added to meet that  
20 growth. In the example, Utah's load was increased an additional 200 MW above  
21 the MSP forecast starting in 2010. Concurrently a 200 MW combined cycle gas  
22 plant was added to meet the additional load. Exhibit No. \_\_\_ (DLT-5) shows the  
23 revenue requirement impacts of meeting the additional 200 MW. In this example,

1 Utah picks up 94 percent in the total revenue requirement increase. While the  
2 example shows an impact of the other States, that impact was minimal.

3 **Q. Why aren't more of the costs of the additional Resource passed on to other**  
4 **States?**

5 A. While all States pick up their proportional share of the higher than system average  
6 costs of the new additional Resource, Utah, the faster growing State in this  
7 example, picks up a larger share of all other allocated costs. As a result of its now  
8 larger allocation factors, Utah picks up a larger share of the costs of the remaining  
9 generation Resources, a larger share of the system's transmission costs, a larger  
10 share of A&G expenses and all other allocated costs.

#### 11 **Revenue Requirement Impacts**

12 **Q. Have you prepared an exhibit showing the impact of the MSP Solution on**  
13 **revenue requirements?**

14 A. Yes. Exhibit No. \_\_\_ (DLT-6) presents estimates of impacts of the MSP Solution  
15 on each State's revenue requirement. Estimated MSP Solution revenue  
16 requirements for California, Oregon, Washington, and Wyoming are compared to  
17 the Modified Accord methodology. Estimated MSP Solution revenue  
18 requirements for Idaho and Utah are compared to the Rolled-In methodology. A  
19 positive percent indicates the States revenue requirement for a given year under  
20 the MSP Solution is higher and a negative percent indicates the revenue  
21 requirement under the MSP Solution is lower. The year-by-year revenue  
22 requirement impacts are shown for the period 2005 thorough 2018 as well as the  
23 Net Present Value of the difference in revenue requirements over the 14-year



1 period. For each State, the percent change in revenue requirement associated with  
2 the Hydro and Coal Endowments is shown first followed by the impact of the full  
3 MSP Solution.

4 **Q. What do you conclude from Exhibit No. \_\_\_(DLT-6)?**

5 A. I conclude that the revenue requirement impacts are within an acceptable range.  
6 The Net Present Value of the change in revenue requirement over the 14-year  
7 period is less than one percent for every State and single year impacts never  
8 exceed plus or minus 2.5 percent. While the MSP Solution produces somewhat  
9 lower revenue requirements for California, Oregon, Washington, and Wyoming in  
10 the early years, the trend reverses and those States see larger revenue  
11 requirements in the later years. The higher MSP Solution revenue requirements  
12 seen by Utah and Idaho in the early years are offset by lower revenue  
13 requirements in the later years.

14 **Q. Have you prepared an exhibit that identifies how all cost components of the**  
15 **revenue requirement are allocated among States?**

16 A. Yes. Exhibit No. \_\_\_(DLT-7), which is Appendix B of the MSP Solution,  
17 identifies the allocation factor applied to each component of the revenue  
18 requirement calculation. Exhibit No. \_\_\_(DLT-8), which is Appendix C of the  
19 MSP Solution, gives a detailed explanation and the algebraic formula for each  
20 allocation factor.

1 **Washington Class Cost of Service**

2 **Summary of Results**

3 **Q. Please identify Exhibit No. \_\_\_(DLT-9) and explain what it shows.**

4 A. Exhibit No. \_\_\_(DLT-9) is the summary table from PacifiCorp's test period ended  
5 March 2003 Class Cost of Service Study for the State of Washington. It is based  
6 on PacifiCorp's annual results of operations for the State of Washington presented  
7 in the testimony of Mr. Weston. It summarizes, both by customer group and by  
8 function, the results of the fiscal year end March 2003 cost study. Page 1 presents  
9 results at the Company's March 2003 Earned Rate of Return. Page 2 presents the  
10 results using the rate of return provided by the \$26.7 million requested price  
11 increase.

12 **Q. Please identify Exhibit No. \_\_\_(DLT-10) and explain what it shows.**

13 A. Exhibit No. \_\_\_(DLT-10) shows the cost of service results in more detail by class  
14 and by function. Page 1 summarizes the total cost of service summary by class  
15 and pages 2 through 6 contain a summary by class for each major function.

16 **Description of Procedures**

17 **Q. Please explain how the Cost of Service Study was developed.**

18 A. Using the March 2003 annual results of operations for the State of Washington  
19 filed by Mr. Weston, the study employs the three-step functionalization,  
20 classification, and allocation process.

21 **Q. How is the functionalization process employed in the Cost of Service Study?**

22 A. Functionalization is the process of separating expenses and rate base items  
23 according to utility function. The production function consists of the costs

1 associated with power generation, including coal mining, and wholesale  
2 purchases. The transmission function includes the costs associated with the high  
3 voltage system utilized for the bulk transmission of power from the generation  
4 source and interconnected utilities to the load centers. The distribution function  
5 includes the costs associated with all the facilities that are necessary to connect  
6 individual customers to the transmission system. This includes distribution  
7 substations, poles and wires, line transformers, service drops and meters. The  
8 retail services function includes the costs of meter reading, billing, collections and  
9 customer service. The miscellaneous function includes costs associated with  
10 demand side management, franchise taxes, regulatory expenses, and other  
11 miscellaneous expenses.

12 **Q. Describe how the classification process is used in the cost of service study.**

13 A. Classification identifies the component of utility service being provided. The  
14 Company provides, and customers purchase, service that includes at least three  
15 different components; demand-related, energy-related, and customer-related.  
16 Demand-related costs are incurred by the Company to meet the maximum  
17 demand imposed on generating units, transmission lines, and distribution  
18 facilities. Energy-related costs vary with the output of a kWh of electricity.  
19 Customer-related costs are driven by the number of customers served.

20 **Q. How does PacifiCorp determine cost responsibility among customer classes?**

21 A. After the costs have been functionalized and classified, the next step is to allocate  
22 them among the customer classes. This is achieved by the use of allocation  
23 factors that specify each class' share of a particular cost driver such as system

1 peak demand, energy consumed, or number of customers. The appropriate  
2 allocation factor is then applied to the respective cost element to determine each  
3 class' share of cost. A detailed description of PacifiCorp's functionalization,  
4 classification and allocation procedures and the supporting calculations for the  
5 allocation factors are contained in Exhibit No. \_\_\_ (DLT-11).

6 **Q. Does PacifiCorp's cost of service study filed in this case follow the**  
7 **methodologies accepted by the Commission?**

8 A. Yes. In the Company's study, we have made our best efforts to follow the cost  
9 allocation guidelines established by the Commission in previous regulatory  
10 proceedings associated with electric utilities operating in the state of Washington.

11 Almost eighteen years ago, in 1985, PacifiCorp's last litigated cost of  
12 service study (Cause No. U-86-02), the Commission did not make a decision on  
13 cost of service methodology. As stated in the Second Supplemental Order, page  
14 39:

15 "The Commission in this case, finds none of the cost of service studies  
16 presented totally acceptable. All have made a meaningful contribution  
17 to the Commission's ultimate determination. The Commission again  
18 declines to adopt any particular method for performing cost of service  
19 studies. The Commission will continue to maintain the view that less  
20 emphasis should be placed on arguments regarding the elements of each  
21 cost of service study and more emphasis place on the application of the  
22 study results."

1           Since that time, the Commission has made decisions on cost of service  
2 methodology for the other investor owned electric utilities in the state.  
3 Additionally, during the spring of 1998, the three investor-owned electric utilities  
4 in Washington participated in an investigation into unbundled cost of service in  
5 Docket No. UE-980181, Analysis of Unbundled Cost Elements of Electricity and  
6 Natural Gas Service. In that docket, PacifiCorp, and others, were directed to file  
7 using the Commission approved methodology.

8 **Q. Does the cost of service methodology employed in this filing follow the inter-**  
9 **jurisdictional allocation procedures outlined in the MSP Solution?**

10 A. No. The MSP Solution is for allocation of costs among states. Each individual  
11 state Commission continues to have full independent authority to determine  
12 methodology on allocation of costs among customer classes within their own  
13 state. Some states may choose, as they have in the past, to adopt the same  
14 allocation methodologies for class allocation as used in inter-jurisdictional  
15 allocation, while other states view the two processes as being more independent.  
16 Again, we have made our best efforts to follow major class cost allocation  
17 guidelines established by the Commission.

18 **Q. How are generation and transmission costs apportioned among customer**  
19 **classes?**

20 A. All production and transmission plant and expenses, including fuel and purchased  
21 power, are classified using a peak credit method where the cost of a current  
22 peaking resource (Simple Cycle Combustion Turbine, SCCT) is compared to the  
23 cost of a current baseload resource (Combined Cycle Combustion Turbine,

1 CCCT). In this method, the SCCT is deemed to provide benefits in addition to  
2 pure peaking capability, and therefore only one-half of the fixed costs are  
3 considered in determining the demand related component. All other costs are  
4 considered energy-related.

5 **Q. Please identify Exhibit No. \_\_\_(DLT-12) and explain what it shows.**

6 A. Exhibit No. \_\_\_(DLT-12) shows the calculation of the demand and energy  
7 classification percentages used for generation and transmission costs in the study.  
8 In the calculation, one-half of the fixed costs of a simple-cycle combustion  
9 turbine plus the expected operating costs for 200 hours become the numerator.  
10 The denominator is the total cost, both fixed and variable, of a base load  
11 combined-cycle plant, run at an 85 percent capacity factor, consistent with the  
12 Company's resource planning and avoided cost calculations. This calculation  
13 produces the 13 percent demand-related classification with the remaining 87  
14 percent the energy-related classification of costs.

15 The demand-related portion is then allocated using class loads coincident  
16 with the PacifiCorp's highest 100 summer (April-October) and 100 winter  
17 (November-March) hourly retail system loads. The energy portion is allocated  
18 using class annual MWh's adjusted for losses to generation level.

19 **Q. Why didn't you use the highest 200 peak load hours regardless of season?**

20 A. PacifiCorp is a dual peaking utility with peaks in both the summer and the winter.  
21 In the March 2003 test period nearly all (198 out of 200) of the peak hours were  
22 in the summer. This would have resulted in no demand-related generation costs  
23 being assigned to electric space heating and other winter loads. At the same time,

1 summer loads, like irrigation and other agricultural loads, would have been  
2 assigned the entire annual demand related generation and transmission costs.

3 **Q. Are distribution costs determined using the same methodology?**

4 A. No. Distribution costs are classified as either demand-related or customer-related.  
5 In this study only meters and services are considered as customer-related with all  
6 other costs considered demand-related. Distribution substations and primary lines  
7 are allocated using the maximum rate schedule peaks (also identified as class non-  
8 coincident peaks). Distribution line transformers and secondary lines are  
9 allocated using the weighted non-coincident peak (NCP) method. Services costs  
10 are allocated to secondary voltage delivery customers only. The allocation factor  
11 is developed using the installed cost of new services for different types of  
12 customers. Meter costs are allocated to all customers. The meter allocation factor  
13 is developed using the installed costs of new metering equipment for different  
14 types of customers.

15 **Q. Please explain how customer accounting and customer service expenses are**  
16 **allocated.**

17 A. Customer accounting expenses are allocated to classes using weighted customer  
18 factors. The weightings reflect the resources required to perform such activities  
19 as meter reading, billing, and collections for different types of customers. DSM  
20 expenditures are allocated on the same basis as generation costs. Other customer  
21 service expenses are allocated on the number of customers in each class.

1 **Q. How are administrative & general expenses, general plant and intangible**  
2 **plant allocated by PacifiCorp?**

3 A. Most general plant, intangible plant, and administrative and general expenses are  
4 functionalized and allocated to classes based on generation, transmission, and  
5 distribution plant. Employee Pensions and Benefits have been assigned to  
6 functions and classes on the basis of labor. Costs identified as supporting  
7 customer systems are considered part of the retail services function and have been  
8 allocated using customer factors. Coal Mine plant is allocated consistent with  
9 generation and transmission resources.

10 **Q. Are costs and revenues associated with wholesale contracts included in the**  
11 **cost of service study?**

12 A. No costs are assigned to wholesale contracts. The revenues from these  
13 transactions are treated as revenue credits and are allocated to customer groups  
14 using appropriate allocation factors. Other electric revenues are also treated as  
15 revenue credits. Revenue credits reduce the revenue requirement that is to be  
16 collected from firm retail customers.

17 **Partial Requirements Service**

18 **Q. Does the Cost of Service Study include results for partial requirements**  
19 **service customers?**

20 A. No. Cost of service results were not calculated for customers taking partial  
21 requirements service customers.

22 **Q. Why are these customers removed from the cost of service study?**

23 A. Partial requirements are not included in the embedded cost of service study



1           because they do not lend themselves well to this type of analysis. These  
2           customers usually have very sporadic loads from year to year, producing volatile  
3           cost of service results depending on whether or not service is required during the  
4           hour of monthly system peak. It is the Company's practice to derive prices for  
5           this type of service from the prices and costs for full requirements service. The  
6           revenues from partial requirements service are allocated back to other classes as  
7           revenue credits.

8   **Q.    Have you included your workpapers?**

9    A.    Yes. Workpapers showing the complete functionalized results of operations and  
10       class cost of service detail are included as Exhibit No.\_\_\_\_(DLT-11). Also  
11       included in the workpapers is a detailed narrative describing the Company's  
12       functionalization, classification and allocation procedures.

13   **Q.    Does this conclude your direct testimony?**

14   A.    Yes.