- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for an Increase in its Rates and Charges	)))	DOCKET NO. 01-035-01 REPORT AND ORDER

ISSUED: September 10, 2001

PROCEDURAL HISTORY

This docket originates from the January 12, 2001, general rate case application of PacifiCorp, d/b/a Utah Power and Light (hereafter PacifiCorp, Utah Power or the Company). In its application, PacifiCorp alleged that it was experiencing an annual revenue deficiency for its Utah operations and sought an increase in prices for Utah tariff customers in the amount of $141,157,165.

With the commencement of this docket, the Division of Public Utilities (hereafter DPU or Division) and the Committee of Consumer Services, Utah Department of Commerce (hereafter CCS or Committee), state agencies which are authorized to appear and participate in proceedings before this Commission, indicated their intent to actively participate in this docket. Petitions to intervene were subsequently filed by numerous entities. On January 29, 2001, intervention was granted for a joint group of large commercial customers, calling themselves the Utah Association of Energy Users (hereafter UAE); composed of Con Agra Beef Company, Hexcel Corp., IHC Hospitals, Thiokol Corp., Western Electrochemical Company, and the Utah Association of Energy Users.(1) Intervention was granted to another group of large commercial customers, calling themselves the Utah Industrial Energy Consumers (hereafter UIEC); comprised of Abbot Critical Care, Fairchild Semiconductor, Amoco Petroleum Products/Salt Lake, Holnam Inc., Kimberly-Clark Corp., Micron Technology Inc., Praxair Inc., Western Zirconium, and Kennecott Utah Copper Corp. Intervention was also granted to United States Executive Agencies (hereafter USEA), Nucor Steel, Emery County, Millard County, the and a joint group of entities representing consumers, known as the Utah Ratepayers Alliance; the latter is comprised of the Salt Lake Community Action Program, Crossroads Urban Center, and the Utah Legislative Watch (hereafter Utah Ratepayers Alliance or URA).

As the proceedings progressed, additional entities sought intervention. On February 7, 2001, intervention was granted to Magcorp and the Office of Energy and Resource Planning, Utah Department of Natural Resources.(2) Later intervention was also granted to the Land and Water Fund of the Rockies (hereafter Land and Water Fund) and the Utah Farm Bureau Federation (hereafter Farm Bureau).

INTERIM RATE RELIEF

Along with its January 12th general rate case application, PacifiCorp also filed an Emergency Motion for interim rate relief during the pendency of these proceedings. Pursuant to the Commission's January 18, 2001, Notice of Hearing, prefiled testimony concerning the interim rate relief request was filed by the Company, the Division, the Committee, and UAE/UIEC submitted joint testimony. A hearing on the interim rate relief request was held on January 30, 2001. The Commission's discussion and consideration of the prefiled testimony and the evidence received at the hearing is contained in the Order Granting an Interim Rate Increase, issued February 2, 2001. In that February 2nd Order, the Commission granted a $70 million interim rate increase, effective on that date, spread through a uniform percentage increase in the usage elements of the Company's rate schedules for tariffed sales in the State of Utah. The February 2nd Order Granting an Interim Rate Relief is attached hereto.

GENERAL RATE PROCEEDING

The general rate case proceedings have been bifurcated into two phases. The first phase, the subject of this order, deals with establishing the Company's Utah revenue requirement. The second phase deals with the cost of service and spread of the revenue change to Utah customers and adjustments of rates to provide the Company with an opportunity to earn the revenue requirement set in this first phase. Pursuant to the Commission's February 23 and May 30, 2001, Scheduling Orders, these two phases have followed or will follow this schedule: February 22, 2001, a technical conference to discuss rate design issues; February 28, 2001, filing of PacifiCorp direct testimony on cost of service; March 15, 2001, filing of PacifiCorp direct testimony on rate design; June 4, 2001, filing of Division, Committee, and interveners' testimony on revenue requirement; June 15, 2001, Division, Committee and interveners file testimony on cost of service and rate design; July 16, 2001, all parties file rebuttal testimony on revenue requirement; July 30-August 1, 2001, hearings on revenue requirement issues[(3)]; August 31, 2001, all parties file rebuttal testimony on cost of service and rate design issues; September 21, 2001, all parties file surrebuttal testimony on cost of service and rate design issues; October 1 - 5, 2001, hearings on the cost of service and rate design issues.[(4)]

REVENUE REQUIREMENT PHASE

In the revenue requirement phase of this docket, PacifiCorp supported its Application with the testimony of Matthew R. Wright, Bruce N. Williams, Samuel C. Hadaway, D. Douglas Larson, Neil L. Getzelman, Brian K. Hedman, Judi A. Johansen, Jeffrey K. Larsen, Stan K. Watters, Daniel C. Peterson, J. Ted Weston, Mark T. Widmer, and Karen K. Clark. The Division submitted the testimony of Mary H. Cleveland, Rebecca L. Wilson, Ronald L. Burrup, William A. Powell, Paul F. Mecham, Carl L. Mower, Thomas F. Peel, Mark V. Flandro, and Laura Nelson. The Committee submitted testimony of Helmuth W. Schultz, III, Kevin B. Cardwell, Hugh Larkin, Jr., John B. Legler, Donna DeRonne, George Sterzinger, and Anthony J. Yankel. The Committee and Division also jointly offered the testimony of Randall J. Falkenberg and Philip Hayet. (Some parts of Mr. Falkenberg's testimony were sponsored solely by the Committee, and the distinctions were explained by Mr. Falkenberg and Division witnesses.) The USEA filed revenue requirement testimony of Joseph A. Herz. The UIEC sponsored testimony of Alan Chalfant and Michael Gorman. The UAE submitted testimony of Richard M. Anderson. The Utah Energy Office provided testimony of David Nicholls and Jeffrey Burks. The Land and Water Fund filed testimony of James F. (Rick) William.

STIPULATION ON CERTAIN REVENUE REQUIREMENT ISSUES

As the case progressed, the parties became aware that, almost universally, all of the parties submitting testimony were addressing PacifiCorp's power costs. Only the Division and the Committee were pursuing broader revenue requirement issues (e.g., capital costs, employee compensation, etc.) beyond those costs which the parties called the "net power cost issues." The net power cost issues, generally, can be viewed as PacifiCorp's fuel costs of generating electricity itself or buying, trading or otherwise obtaining electricity from other entities in order to provide electric service to PacifiCorp's retail customers.[(5)] Through negotiations, PacifiCorp, the Division and the Committee were able to reach a settlement agreement on the overall dollar impact which these non-net power cost issues would have on the revenue requirement increase requested by PacifiCorp. The stipulation also addressed some net power cost issues. On July 12, 2001, PacifiCorp submitted a Motion for Approval of Stipulation on Certain Revenue Requirement Issues which requested Commission approval of the three parties' stipulation. The Commission held a hearing on the request to approve the stipulation on July 26, 2001. At the hearing, the three parties' witnesses provided testimony in support of the Commission's approval of the stipulation. No other party opposed approval of the stipulation. By Order issued August 17, 2001, the Commission approved the stipulation, by which approximately 100 contested issues affecting the revenue requirement determination were resolved. Issues related to the net power costs claimed in the Application were reserved for resolution at the previously scheduled revenue requirement hearings. The Commission's August 17, 2001, Order Approving the Stipulation on Certain Revenue Requirements and the Stipulation are attached.

By the terms of the Stipulation, the parties agreed that the Company's cost of capital used for establishing the revenue requirement in this case should be based on a hypothetical capital structure of 47.6% common equity, 49.2% debt and 3.2% preferred stock, with a return on common equity of 11%, a return on preferred stock of 6.182% and a cost of debt of 6.991%, resulting in an overall 8.873% rate of return.

NET POWER COST ISSUES

The net power cost issues are diverse, ranging from adjustments to PacifiCorp's short-term firm and non-firm sales and purchases with other entities, to adjustments for impacts on PacifiCorp's maintenance activities for its own thermal generating plants, to adjustments for the price of coal supplied to some of PacifiCorp's thermal generating plants. The parties' proposed calculations for determining the impact these various adjustments have on the revenue requirement are also diverse and represent significant divergence on the ultimate revenue requirement conclusion. Most of these adjustments reflect multi-million dollar differences in a party's view of the appropriate revenues, expenses or costs which should be included in determining PacifiCorp's revenue requirement. In this Order, we consider the parties' positions on these net power cost adjustments, resolve the disputes for rate making purposes and incorporate our resolution of the disputed net power cost issues with the prior resolution of other non-net power cost issues. We arrive at a final revenue requirement which we will use in designing rates in the next phase of these proceedings.

At the July 30 - August 3, 2001, hearings on these net power cost issues, PacifiCorp was represented by Edward Hunter, John Erickson, and James M. Van No strand, of Steel Rives. The Division was represented by Michael Ginsberg and Kent Walgren, Assistant Attorneys General, Utah Attorney General's Office. The Committee was represented by Reed Warnick, Assistant Attorney General, Utah Attorney General's Office. The USEA was represented by Robert C. Cottrell. The UIEC was represented by William J. Evans, of Parsons, Behle & Latimer. The UAE was represented by Gary A. Dodge, of Hatch, James & Dodge. Nucor was represented by Peter J. Mattheis, of Brickfield, Burchett, Ritts & Stone. The Farm Bureau was represented by Stephen Randle. The Utah Ratepayers Alliance was represented by Bruce Plenk. The Utah Energy Office was represented by Steven F. Alder, Assistant Attorney General, Utah Attorney General's Office. The Land and Water Fund was represented by Eric C. Guidry.

PacifiCorp presented the testimony of Karen Clark, Brian K. Hedman, Judi A. Johansen, Jeffery K. Larsen, D. Douglas Larson, Stanley K. Waters, and Mark T. Widmer. The Division provided the testimony of George R. Compton, Judith Johnson, Philip Hayet, Laura Nelson, and Rebecca L. Wilson. The Committee presented the testimony of George J. Sterzinger and Anthony J. Yankel. As noted previously, both the Division and the Committee provided the testimony of Randall J. Falkenberg, with the conditions noted. The USEA presented the testimony of Joseph A. Herz. The Utah Energy Office supplied the testimony of Jeff Burks and David Nicholls. The UAE sponsored testimony of Richard M. Anderson. The UIEC provided testimony from Michael Gorman and Alan Chalfant.

NET POWER COSTS

As an outcome of Docket No. 99-035-10, the Commission requested an evaluation of alternative approaches to the normalization of net power costs due to a less than fully successful experience with the Company's Production Dispatch for Macintosh model, termed PD/Mac. (May 24, 2000 Report and Order, p. 43.) On reconsideration, the Commission informed the Company that should it file a general rate case application before the evaluation was complete, a reformatted production dispatch (PD/Mac) model or an alternative to that model must be submitted with the application. (October 6, 2000 Order on Reconsideration, pp. 4 - 5.) In accordance therewith, the Company employs an alternative spreadsheet model to normalize net power costs in the present Docket.

Net power costs are the costs of fuel at Company thermal generating units plus the costs of wholesale power purchases and wheeling less the revenues from wholesale sales. To normalize net power costs for ratemaking, much of the test-year information used in the spreadsheet model is first adjusted. Firm retail loads are weather normalized. The prices and volumes specified in long-term firm wholesale sales and purchase contracts are annualized based on changes occurring within the test year as called for by the contracts. Short-term (one year or less) firm sales and purchases are based on contract volumes and adjusted prices. Fifty years of data covering monthly hydroelectric generation for Company-owned hydro plants in the Pacific northwest plus Mid-Columbia purchased resources are employed to model the output of hydro resources under normal water conditions.

For each thermal unit, normalized information on maximum and minimum generation capacity, availability, and maintenance is employed. Given the prices of fuel and non-firm purchases, the spreadsheet determines the output of thermal plants on an economic basis. For example, at higher fuel prices and lower non-firm purchase prices, volumes of non-firm purchases replace thermal plant output, and vice versa. In other words, substitution occurs between volumes of thermal generation and non-firm purchases based on relative prices.

The Company assigns firm loads and resources, both contracts and thermal generating units, to two divisions, Pacific and Utah. The Pacific hydro resources are presented for each month of each of 50 years, 1929 through 1978, whereas the volumes of Utah hydro resources, relatively small in amount, are calculated as actual monthly averages for the years 1974 through 1999. The balances of long-term firm load and resource volumes of each division are then separately calculated for each month of the 50-year period, and Utah's balance, while varying by month, does not vary by year. The model then calculates the volumes of non-firm sales and purchases, by division, necessary to balance each division's firm loads and resources. Average prices are used to value these non-firm volumes in order to arrive at a final value of net power costs. This is a monthly average model and makes no distinction between peak and non-peak system operating conditions.

Model inputs are contested by the parties. These inputs include appropriate prices for short-term firm and non-firm wholesale transactions, losses on short-term transactions, thermal unit availability and maintenance, Cholla unit outage, and treatment of the Gadsby units. Also at issue is the appropriate transmission modeling and integration of the two divisions. In addition, the Division, the Committee and the UAE would impute revenues to long-term firm sales contracts said to be underpriced.

As presented in the Company's direct testimony, the two divisions were modeled as independent entities without any transmission interconnection. Each division's load and resource imbalance was therefore separately met by non-firm market transactions. After being challenged on this point by the Division and the Committee in testimony indicating a reduction in net power cost due to the physical transmission linkage between the divisions, the Company responded on rebuttal with a modeling effort to incorporate the transmission interconnection between divisions.

Three net power cost adjustments (incremental coal discount, WAPA wheeling contract, and the P and M strike amortization) have been included in the Stipulation on Certain Revenue Requirement Issues. (Order Approving Stipulation on Certain Revenue Requirement Issues, August 17, 2001.) A fourth adjustment, resolved by the Company and the Division, settles a dispute over Glenrock mine costs.

- Short-Term Firm and Non-Firm Sales and Purchase Prices

In the Company's spreadsheet model, the prices of short-term firm transactions are used to value the fixed test-year volumes of short-term firm sales and purchases. These are the unadjusted volumes resulting from actual decisions made in the context of test-year circumstances. Given short-term and long-term firm loads and resources of the two divisions, prices of non-firm purchases and sales are an important factor in determining the volumes of each division's non-firm transactions. In addition to valuing transactions, non-firm purchase prices are also a key factor in the economic dispatch of thermal generating units. Despite the large pricing differences between the Company and the parties, the value of net power costs, while somewhat sensitive to short-term firm prices, is in this case far more sensitive to non-firm prices, particularly when, as in the test year, PacifiCorp relies on non-firm market transactions to balance firm loads and resources.

The Company proposes to annualize short-term firm and non-firm sales and purchase prices by spreading the effect of the very high prices actually experienced in June through September 2000, to the earlier months of the test year, October 1999 through May 2000. Prices for these early months are shaped using monthly averages of wholesale market prices recorded in Dow Jones Indices relative to an average of the actual June through September prices. The result is a set of monthly prices for the entire test year much higher than actually experienced. The Company believes this is appropriate based on its expectation that very high prices will continue in coming months. The Division, the Committee, and the UIEC dispute this position and recommend the use of actual rather than adjusted prices, citing to a Commission decision in the previous rate case, Docket No. 99-035-10, adopting actual prices. No other party testifies on this issue.

The Company believes its proposed annualization of test-year prices is consistent with the Commission's annualization rule according to which known and measurable changes that occur within a test year may be made effective for the entire year. Price increases that occurred in the final months of the test year, the Company testifies, should be the basis for an upward adjustment to the prices of earlier months. The other parties argue that such an adjustment does not meet the rule's requirement that price changes must be both known and measurable. The Rule states "the change must be known to occur at a specific moment or moments in time," and "the change must be expected to be ongoing after final rates become effective." (R746-407-3 D and G.) Not only do the Division and the Committee not expect the price changes to be ongoing, but they claim the Company's use of Dow Jones Indices to shape October through May prices is inappropriate because the Indices are based on selective and proprietary survey data which is unrepresentative of the Company's actual transactions. Thus, neither of the rule's requirements, these parties testify, is met. The Company's approach is further criticized because, in its use of monthly averages, daily and hourly price changes as well as non-market considerations are ignored. This is a modeling flaw, UIEC argues, of considerable consequence.

Our annualization rule requires a change occurring during the test year to be ongoing. Given the extreme volatility of the regional wholesale market, and the record in this Docket, we find no basis for assurance that the high prices experienced in the June through September period will continue. The Company acknowledges as much, citing as reasons for the recorded recent decline in wholesale prices the effect of conservation, cooler weather, the newly introduced FERC price caps, the removal of nitrous oxide costs from price caps, and a general economic slowdown. We are aware that drought in the Pacific Northwest has adversely affected the availability of hydro resources, and this in turn is an important contributing factor to regional wholesale price increases during the test year. Hydro conditions of this sort cannot be assumed to continue; indeed, the variability of hydro resources from year to year is the very reason that net power cost modeling normalizes Northwest hydro conditions based on a 50-year experience. We also know that institutional and structural changes in the regional wholesale market have occurred. A key example is how California's load is served. Formerly, a large portion of California's load was served by California Power Exchange purchases on the day-ahead spot market. This was a source of much of the volatility in the regional wholesale market. Now, however, the Power Exchange has been disbanded, and California's needs are in large part being met with long-term contracts secured by the State. Beyond this, and as a conceptual concern, future prices are unknowable in advance. For all such reasons, we have no confidence that the Company's annualization procedure adequately captures changes of an ongoing nature. Accordingly, the Company's proposed annualization of short-term firm and non-firm prices is not accepted. As in past dockets, actual prices will be employed in net power cost modeling.

Two sets of actual prices appear on the record. No difference appears between them with respect to short-term firm prices, however they do vary with respect to non-firm prices Both sets of prices were supplied to parties by the Company in answer to data requests. Differences between the non-firm prices arise, according to a Company clarification filed later in the proceeding, because those used by the Division/Committee include exchanges as well as non-firm transactions. The Company calculated and provided to UIEC non-firm sales and purchase prices on a locational basis, while the Division/Committee calculated them on a total Company basis.

On this record, we have only PacifiCorp's adjusted prices, which we reject, and actual prices. Because the UIEC non-firm prices exclude exchanges and recognize locational differences, the actual prices which we accept for use in determining normalized net power costs are those supplied by UIEC. In adopting the actual prices, we do not mean to preclude the possibility that other means of adjusting prices, on a future record, could be persuasive.

A consequence of the decision to use actual prices is that the Committee's proposed imputation for the Deseret long-term firm sale contract is unnecessary. The Company increases the revenues and decreases the loads associated with this contract in its rebuttal testimony. The Committee agrees in its surrebuttal testimony that if the Commission adopts actual prices, no imputation of revenues to this contract is necessary. We so find.

2. <u>Short-Term Firm Transactions; Removal of Losses</u>

As in the last general rate case for this company, Docket No. 99-035-10, this Commission is asked to remove losses from short-term firm transactions. These losses result from a difference in short-term wholesale firm purchase prices and short-term wholesale firm sales prices. The Committee argues that losses are not normal and are not expected to be on-going and that this adjustment limits the ratepayers' risk from the Company's trading activities. The Committee calculates losses by using the difference of the average monthly sales price from the average monthly purchase price.

The UIEC also recommends a disallowance for losses on the wholesale market. The UIEC provides a more rigorous calculation than the Committee in that they develop an hourly model that attempts to balance loads and resources, thereby allowing them to segregate short-term wholesale transactions. Unlike the simple averaging approach used by the

Committee, UIEC believes it is critical to avoid time-related differences in comparisons of costs and revenues assigned to wholesale transactions. The analysis begins by determining, on an hourly basis, the Company's total sales requirements, which includes: native load, long-term and intermediate-term sales commitments plus exchanges and other miscellaneous requirements. Generation, long-term and intermediate-term purchases, positive exchanges and miscellaneous transactions are subtracted from total sales requirements to get net requirements. If net requirements are positive, then the Company has more sales commitments than it does resources and must make short-term purchases on the market. The UIEC assigns the lowest priced purchases until all requirements are met. The remaining higher priced purchases are assigned as short-term purchases in support of short-term sales and losses and profits are aggregated over the adjusted test period.

The Company refutes that losses actually occurred in short-term firm transactions and finds fundamental flaws in the methodologies used by the Committee and UIEC. To rebut the Committee's average price comparison, the Company, through cross-examination Exhibit 23, shows that no loss was incurred when transactions were separated between on-peak and off-peak power. The Company also points out that it is difficult to match loads and resources with single transactions. The Company might purchase a block of power to cover a shortage anticipated for a super-peak period, which would then make them long in the shoulder hours of the peak period. Because the value of the leftover shoulder-hour product is less than the super-peak product, the Committee's methodology would calculate a loss when in reality no loss occurred, argues the Company.

The Company also finds deficiencies in the UIEC calculations. First, the UIEC adjustment uses data in October and November 2000, which is outside the test period, and the Company argues that non-firm transactions need to be excluded because they are handled elsewhere in the case. We agree with the Company that this proposal violates our test year construct as well as ignores the normalization process used for non-firm transactions. Second, while the Company recognizes that UIEC makes a more detailed comparison of short-term firm transactions with an hourly model when compared with the Committee's adjustment, the Company believes three additional major changes are required. These changes relate to the time of execution of the contracts, like-kind product comparison, and similar location comparison. The Company points to its rebuttal testimony, specifically the analysis performed in UP&L 5.7 and 5.8 R as evidence that when these factors are taken into account, no material losses exist.

The Commission believes that the record in this case is more fully developed on this issue than in Docket No. 99-035-10. We agree that wholesale transactions cannot be viewed in isolation and independent from the processes used by the Company to balance total loads and resources. Short-term wholesale transactions can be made for a variety of reasons. Some parties conjecture that short-term transactions were made for speculative reasons; the Company anticipated that it could outwit the market by covering sales commitments with short-term purchases. The risk of such transactions should be borne by shareholders. Other transactions are made as part of a hedging strategy, purchasing power to meet a future unanticipated shortfall. Such transactions could prove beneficial or not, but are judged based on information known at the time of the transaction. Transactions also are made to take advantage of arbitrage situations where power can be purchased for less in one location than it is sold at another location, all within a very short time horizon. These transactions should almost always prove profitable. The Commission finds that prudent hedging and arbitrage transactions are legitimate strategies to help lower net power costs. However, ratepayers should be insulated from speculative trading strategies. The Commission does not have a record on which to base a finding on what percentage of short-term wholesale transactions were made on a speculative basis.

Further, a strict comparison of short-term firm sales and purchase prices does not take into account the realities of the different transactions cited by the Company to balance the system. While an hourly analysis provides greater detail, it is still incomplete in calculating an amount that could be identified as truly a loss. Based on the thorough discussion within this record, we do not find cause to adjust the revenue requirement as advocated by the Committee or the UIEC. However, in a later adjustment, we will address the Company's practice of using short-term purchases to cover long-term contract obligations.

- <u>Thermal Unit Availability and Maintenance</u>

As a general proposition, the greater the output of the Company's thermal generation during the test year the less it is required to rely on the non-firm wholesale market to balance firm loads and resources. This is of particular importance in the present Docket since, due to very high wholesale market prices during the test year, small changes in thermal output can have significant impacts on net power costs.

Thermal output is determined by operating equivalent availability and hours of maintenance. The Company employs four-year averages of operating availability and maintenance hours in order to normalize year-to-year variations and thereby to determine on a normalized basis the monthly average capacity available for each thermal unit in its system. The use of four-year averages is disputed by the Division, the Committee and the USEA who recommend six-year averages for all units but Gadsby. Gadsby is treated below as a separate issue.

Past regulatory practice in this jurisdiction, including Company filings and our previous rate cases, is cited by the Company in support of four-year averages. With respect to thermal availability, parties, however, point to a declining trend in the years since 1994. The Company responds that 1994 was the year of highest thermal availability and that availability was lower during the 1991 through 1993 period. The Company provides evidence comparing average availability during the past 10 years with its proposed four-year average. This comparison reveals little difference between 10-year and four-year averages, according to the Company.

With respect to each thermal unit's maintenance hours, the Company also proposes an average of the four-years, 1996 through 1999, to normalize maintenance experience for all units. The parties propose six-year averages for all units, except Cholla, because a disproportionately large number of maintenance hours in 1997 and 1998 renders the Company's proposed four-year average incapable of properly normalizing historical variations. The Division and the Committee propose to treat Cholla differently because of an unusually long outage there. Cholla is separately discussed below. According to the Division and the Committee, six years of data better captures the full impact of all maintenance outage cycles experienced by generating units than does the Company's four-year average. In addition, USEA states that the Company's proposed number of maintenance hours is greater than that adopted in either of the prior two rate cases in this jurisdiction, whereas USEA's six-year proposal is near the mid-point of the two.

USEA also recommends shifting the schedule of maintenance so that it has a less material impact on net power costs. Specifically, the Company proposes to schedule eight units for maintenance in June, whereas USEA, noting that the Company in the past has scheduled maintenance in winter, proposes to move four units to the off-peak months of February and April. The Company responds that it is constrained in its ability to schedule maintenance due to contracts regarding the use of plant, availability of contract labor, and weather.

We will retain the use of four-year averages for thermal availability. Information in the record shows that four-year averages approximate a longer 10-year experience better than do the six-year averages proposed by the other parties.

We will also retain the use of four-year averages for maintenance hours. It is true that maintenance hours for 1997 and 1998 are disproportionately high in comparison to other years in the 1994 to 1999 period. In order to justify a change in our practice of using four-year averages, however, we require a thorough analysis of maintenance requirements. On this record we merely have a discussion of patterns in data. Moreover, we find no basis in the record to alter maintenance scheduling for ratemaking purposes as the USEA proposes. We are reluctant to base so important a decision on an inadequate foundation because of its potential to influence future performance of maintenance and the resulting reliability of the system in a manner adverse to ratepayers.

- Cholla Outage

Planned maintenance at the Cholla Unit No. 4 was extended in 1996 due to unanticipated problems resulting in a 3,124 hour outage. This unusually long outage is included in the four-year average of maintenance hours proposed by the Company to normalize maintenance to determine net power costs. The Division and the Committee propose to exclude it as atypical, and use only the remaining five years of their proposed six-year, 1994-to-1999, period to normalize Cholla Unit maintenance hours. No other party testifies on this issue.

In support of the adjustment, the Division and the Committee believe the Company's application for deferred accounting treatment of the recent Hunter Unit No. 1 outage suggests that, rather than bearing the risk of extraordinary plant outages between rate cases, the Company intends to apply for such accounting treatment. If this is so, and the Division and the Committee acknowledge the Company has not stated it as a definite intention, any such outages should be removed from normalized net power costs. Were the Company to agree that it would not request deferral for a long plant outage the adjustment, they state, would not be necessary. Second, they argue unusual events should be removed from ratemaking as abnormal and nonrecurring.

Had the replacement power costs associated with the Cholla outage been recovered, the Company agrees removal from the normalized calculation would be appropriate. But because it did not seek recovery of replacement power costs and because there is risk the Commission may not grant such recovery, the Company argues the adjustment is not appropriate. The Company also notes the lack of similarity between the Hunter and Cholla outages. Hunter was a catastrophic failure that occurred during the peak season. Cholla was a planned outage that occurred at a time replacement power costs were inconsequential.

We will not accept the proposed adjustment. Data on maintenance reveal that a large number of maintenance hours is not unusual. For example, the Hunter Unit No. 3 in 1998 underwent 2,479 hours of maintenance, and Hayden Unit No. 1, also in 1998, had 2,430 hours. All other outages in the years from 1994 to 1999 were less than 1,800 hours. At the other extreme, there are instances during 1995 and 1996 when no hours of maintenance are recorded at some units. Thus, maintenance data reveals unexplained high and low numbers. We also observe that the year in which the Cholla outage occurred has the lowest total number of maintenance hours in any year of the four-year period, 1996 to 1999. Thus, the inclusion of Cholla does not undermine our objective of obtaining a normal number of maintenance hours from this calculation. Insofar as four-year averages have been used in prior dockets, the large number of maintenance hours associated with the 1996 Cholla outage and those mentioned of somewhat shorter but still long duration have been included in prior net power cost calculations. We therefore conclude that maintenance data for the relevant period provide no clear reason to eliminate the Cholla outage.

In response to the questioned impact on this adjustment of potential filings for deferred accounting treatment of prolonged outages, we state that deferral accounting treatment is in our view an extraordinary measure. We are reluctant to reduce maintenance hours in normalized net power costs since doing so may encourage the Company to seek such treatment for outages of this sort. Though we have not yet considered it on an evidentiary record, the Hunter outage appears to be different in that it occurred during the unusual market circumstances of 2000 - 2001, making replacement power cost the issue. Cholla, on the other hand, occurred in 1996, a period of presumed normal wholesale market conditions. For this and other reasons mentioned here, the two may not be comparable.

- Spinning Reserve and Modeling of the Gadsby Units

In direct testimony, the Company models spinning reserve requirements by decreasing the capacity rating of certain thermal plant units. The Division and the Committee criticize this approach, arguing that resulting maximum capacities are, upon examination of hourly generating logs, too low. They propose higher capacity values. In rebuttal, the Company presents a modeling of spinning reserves which the Division and the Committee in surrebuttal accept. The remaining dispute concerns the modeling of the Gadsby units as peaking units, involving assumptions about equivalent availability and minimum capacities.

For Units 1 and 2, the Company advocates the use of 75 percent equivalent availability for July through September, and 57 percent for the remaining months; for Unit 3, 98.53 percent availability for July through September, and 75 percent for the remaining months. When the price of non-firm purchases is less than the fuel cost of running these units, they can be displaced, according to the Company, down to 57 percent of their dependable capacity after allowance for spinning reserve. The result is a Company specification of minimum capacity for these units. USEA recommends a six-year weighted average of system equivalent availability, or 92.41 percent, for the Gadsby units, and accepts the Company's 57 percent displacement limit. The Division and the Committee recommend equivalent availability varying between 95 and 98 percent depending on unit and month, and advocate a lower displacement limit of 13 percent.

The parties point to capacity factors which result from these assumptions. Non-firm prices, in conjunction with the assumptions about availability and displacement limits, determine the extent to which the Gadsby units are operated. Given the high adjusted prices of non-firm purchases advocated by the Company, and as modeled by it, the Gadsby units run at an overall annual capacity factor of 49 percent. This, states the Company, compares favorably to a 48 percent capacity factor for these units during a recent period of high market prices. USEA's higher equivalent availability, when combined with the Company's adjusted non-firm purchase prices, models the Gadsby units at a 63 percent annual capacity factor. This is unrealistically high given our decision to use actual prices, which are lower than the adjusted prices proposed by the Company. Hence, we consider the USEA position no further. With the Division - Committee assumptions of high equivalent availability, lower displacement limits, and lower (actual) non-firm prices, the modeling result is an annual capacity factor of 33 percent.

Since we use actual non-firm purchase prices, we conclude there is no basis for a Company assertion that the result of the Division - Committee proposed modeling of the Gadsby units is a 63 percent capacity factor. In addition, the Company's proposed lower availability and higher displacement limits, necessary to reflect its higher adjusted prices, produces less variation in monthly capacity factors than does the Division - Committee position: a high of 59.7 percent to a low of 45.4 percent for the Company versus 68.1 percent to 8.5 percent for the Division - Committee. The greater variation in the latter is a product of the lower non-firm purchase prices the Division and the Committee advocate (prices we have adopted above), permitting greater substitution of non-firm purchases for Gadsby plant output. This, we find, better reflects the economic dispatch of generation plant. Thus we conclude both the level of and the variation in capacity factors that result from the Division - Committee approach better represent normal operation of the Gadsby units. These are peaking units with high fuel costs that, according to the Company, are also run for voltage support during periods of peak demand. We therefore accept the Division - Committee position on the Gadsby issue.

- <u>Transmission Capacity; Size of Non-Firm Markets; Optimizing Logic</u>

With the decisions we have reached thus far, including the prices of non-firm purchases by Pacific and Utah divisions, the net power cost model determines the use of each division's thermal units. This is a primary purpose of the model. Its other main purpose is to determine the volumes of non-firm transactions. With these volumes, and using the prices of non-firm purchases and sales, the value of non-firm transactions is derived and included in net power costs. The value of non-firm transactions is a function of the manner in which integration of the two divisions is modeled. We therefore observe that the volume of thermal unit generation and the volume of non-firm transactions are the only elements of the net power cost study subject to optimization.

In direct testimony, the Company files a spreadsheet in which the Pacific and Utah divisions of the PacifiCorp system are modeled as independent entities. This means each division's load and resource balance must be met separately through wholesale transactions in markets specific to each; that is, internal transmission connections between the two, whether east-to-west or west-to-east, are neither used to balance divisional loads and resources nor to exploit Company-wide non-firm wholesale market opportunities.

Observing this, and under the pressure of time introduced by the filing schedule, a modeled integration of the two divisions which quantifies the benefit of internal transmission and external market opportunities is jointly sponsored in direct testimony by the Division and the Committee. The Company responds in rebuttal by providing its own model of integration. This model introduces limits on transmission capability between divisions which are said to correct those the Company had previously provided to the Division/Committee. The Company also at this time introduces limits on external market sizes.

Based on its proposed adjustments and accepting the Company's new transmission limits, the Division/Committee quantifies a $13.7 million reduction in total-Company net power cost due to integrated operations. Using a different optimization method and introducing limits on the size of external markets, based on its proposed assumptions the Company quantifies an effect of integration on net power cost of less than $1 million on a total company basis. The Division/Committee questions the external market size constraints used by the Company and argues that the Company approach fails to optimize the system properly.

Due to inadequate opportunity for review, the Division/Committee accepts, and argues the Commission should accept, the Company's corrected internal transmission limits for purposes of this Docket only. The limits on external market size are unacceptable, the Division/Committee asserts, because they are subjective, unreasonable, difficult to validate, and contrary to those contained in PacifiCorp's new RAMPP 6 report. In addition, the average monthly deficits and surpluses experienced by the Company are said to be relatively small compared to the size of surrounding markets. The Company insists its market limits reflect its ability to buy and sell power given firm transmission rights to wholesale markets and the limitations imposed by existing transactions.

Our examination of the record, including the filed models, shows that the methods used by the Company and by the Division/Committee differ in two respects. First, as stated above, the Division/Committee rejects the use of external market limits. As a consequence, we observe that when both divisions are in surplus or both are in deficit, the results of the two approaches appear to differ not with respect to optimizing routine but only with respect to the application of the market limits. Second, the optimizing routines of the two parties do differ when one division is in surplus and the other is in deficit. Generally in these cases, the surplus of one division is first used to satisfy the deficit of the other, subject to internal transmission limits. If any surplus remains after the transfer, additional sales are made, subject to transmission limits, in the external market where the sale price is higher. Likewise, if there is any remaining deficit after the transfer of the surplus, additional purchases are made in the external market where the purchase price is lower, again subject to internal transmission limits. The consequence is that when the price of sales in the division with the surplus exceeds the price of purchases in the division with a deficit, the surplus is used not to make the higher value sale but to displace the lower value purchase. Flexible operations would allow the sales to be made at the higher price in the division with the surplus and the purchases to be made at the lower price in the division with the deficit. Thus, integrated operations in this price circumstance result in higher net power costs than do independent operations. The Division/Committee routine allows a choice between independent and integrated operations, depending on the price circumstances, when the result is to reduce net power costs. The Company's routine does not.

We conclude that neither party's attempt to optimize the system by modeling the integration between the two divisions is satisfactory. We reach this conclusion in spite of the fact that neither party's model was fully and critically reviewed on the record. The Company filed only at the rebuttal stage and then only in response to the effort of the Division/Committee. No discussion of the details of the optimizing methods occurred; details are only to be found buried in the spreadsheets filed by the parties following the hearings. Of the two, we find the Division/Committee model provides for more economic operation of the system, but find reasons to conclude that neither is adequate for use beyond this Docket. Finally, we note that the effect of including the Company's proposed market limits is immaterial.

First, neither party models the distinction between peak and off peak transactions, yet repeatedly on this record we observe that the distinction is critical to an understanding of how the system of generation and transmission is actually operated. For example, the value of exchanges using Utah thermal resources off peak to replace Pacific use of hydro resources on peak is ignored. Second, neither party allows transactions within a division to take advantage of market opportunities. An example would occur when the sales price in the external market facing one division is greater than the purchase price in the external market facing that same division. Third, optimizing transactions with external markets often requires the Company to incur wheeling charges, but the access to markets made available by wheeling is not modeled. Fourth, when the system is in balance, neither party's optimizing routine permits non-firm transactions to occur. This is perhaps a simplifying assumption but it bears little resemblance to the opportunities available to the Company. Finally, when the Division/Committee's proposed non-firm prices are employed, neither purchase nor sales prices differ between divisions. There is a single monthly purchase price and a single monthly sales price applicable to both divisions, simplifying the optimization problem by eliminating the opportunity to substitute purchases and sales between divisions based on price differences. To be acceptable for net power cost normalization in this jurisdiction, a modeling routine intended to optimize the economic interaction between the two divisions must successfully address these points.

We find record support for the proposition that value exists in integrated system operation to a degree not fully captured by either Company or Division/Committee modeling efforts. Indeed, that there would be significant value in a fully integrated, single-system operation was a principal reason this Commission approved the 1989 merger of Pacific Power and Utah Power. The Company now offers neither complete nor coherent argument as to why these operational benefits should have disappeared. For this reason, plus our findings that the Division/Committee approach appears to capture a more realistic picture of the economic choices the two divisions could be expected to face as they respond to either surplus or deficit, we accept the results of the Division/Committee analysis. We conclude that $13.7 million is the only amount on this record reasonably suggestive of the value of integrated system operations.

- <u>Long-Term Firm Sales Contracts; Imputation of Revenues</u>

Sacramento Municipal Utilities District (SMUD) Contract

As in the immediately preceding general rate case for this Company, Docket No. 99-035-10, this Commission is asked to impute revenues to a 1987 long-term firm wholesale contract with SMUD to counter the contract's adverse impact on the net power cost portion of jurisdictional revenue requirement. In that Docket, the Commission did order imputation because the contract obligated the Company to serve SMUD at $16.85 per MWh at the time it was entered, a rate much below the then-current rate for power. In addition, SMUD paid the Company $94 million at the outset of the contract that it retained and was not used to benefit ratepayers. Nor was this the first time the imputation had been made. In connection therewith, both here and in other PacifiCorp jurisdictions, a contract with Southern California Edison (SCE) entered at about the same time for $42 per MWh had been considered an appropriate benchmark for imputation. The evidence in Docket No. 99-035-10 showed that the SCE contract had been renegotiated to a rate of $37 per MWh due to structural changes in the wholesale market. In other words, the Commission recognized that wholesale prices, which had fallen, were now on a different path. This, and the fact that the renegotiation was closer in time to the test period, persuaded the Commission to select the $37 rate as the basis for imputation, a rate indicating how such a contract might perform over time.

In the present Docket, the Company does not dispute imputation, but argues for continued use of the $37 rate from the renegotiated SCE contract as a fair basis. The Division and the Committee argue the rate used should correspond to test-year circumstances. Given SCE contract terms, that rate is $47.70. Other parties support revenue imputation; no party opposes it.

As in Docket 99-035-10, we find that revenue imputation to the SMUD contract is warranted in this case. We consider whether its basis should be $37 or $47.70.

PacifiCorp argues the Commission's use of $37 in the previous case does not suggest an intent to impute revenues based on the actual SCE contract price during the test year. Renegotiation of this contract, states the Company, occurred in 1995, and the rate for the first year following that is $37, the amount used by the Commission. PacifiCorp informs us that power cost data in Docket No. 99-035-10 contains a test-year SCE contract price of $49.42, which, it alleges, should have been used if the intention was to base imputation on a test-year contract price.

We seek a reasonable basis for imputation, once we decide an imputation must be made. In the previous Docket, $37 was such an amount, because it was the most current contract price debated on the record and it recognized structural changes in the wholesale market. No party advocated the test year figure of $49.42 the Company now calls to our attention. In fact, no party mentioned the figure in that Docket and we were not aware of it.

The Company further argues that because certain SCE contract terms call for a price in 2001 much higher than the test year $47.70, the contract should no longer be considered a relevant benchmark for revenue imputation. Parties advocating imputation do so on the basis of the SCE contract. Even the Company supports the $37 renegotiated SCE contract price for this Docket. We therefore believe arguments opposing further use of the SCE contract are appropriately a subject for the next general rate case in which SMUD revenue imputation arises.

Issues parties enumerate that distinguish the SMUD contract from the other contracts to which we impute revenue in this Docket include an initial payment of $94 million. We concur that these factors separate the SMUD contract from other contracts and can be considered in making the imputation. In PacifiCorp's last general rate case we used the SCE renegotiated contract to impute revenues to reflect changes in the wholesale market that affected a contract similar to SMUD's that was executed at about the same time. We also sought to use data closest to the test year in that case which is one of the reasons we used the renegotiated price of $37.

In this Docket we learned that the actual test year SCE contract price in Docket No. 99-035- 01 was $49.42. The $37 price, therefore, was not the closest figure to the test year in that case though it was more reflective of the changes that had occurred in the wholesale market than the terms of the SMUD contract. We also discovered that the SCE contract is indexed to the Southern California border price of gas, a fact that could lead to unintended results not fully explored on this record. Our objective is to impute revenues to the SMUD contract to make it compensatory. The only proposals before us are to apply $37 or $47.70 to the SMUD contract. After the testimony and argument in this case, there are enough questions about the SCE contract as an appropriate reference that we will not depart from our previous decision by increasing the imputation to $47.70. Consequently, we accept the $37 per MWh figure and await further argument in a future case.

- Long-Term Firm Wholesale Sales Contract Revenue Imputation[(6)]

Four parties, the Division, the Committee, UAE Intervention Group, and Nucor Corporation, propose to impute revenues to underpriced long-term firm wholesale sales contracts entered by PacifiCorp largely after 1995. Each seeks revenue imputation in order to protect retail ratepayers from the adverse effect of these contracts on net power costs, which, they assert, arises from the Company's strategy to rely on the wholesale market to meet this wholesale sales commitment. UAE/Nucor argues that after 1995 the Company adopted a strategy intended to expand the Company's wholesale market presence, distinct from regulated utility requirements, as a business purpose in itself. The result, they state, exposes captive retail ratepayers to unwarranted risk, which translates in this Docket to an increase in net power costs of unprecedented dimension. The amount of the proposed imputation varies by party due both to the selection of contracts to which it would apply and the basis for the imputation calculation. All parties except PacifiCorp support imputation.

The Commission approved revenue imputation to long-term firm wholesale sales contracts in PacifiCorp general rate case Docket No. 99-035-10. The amount was based on an avoided-cost calculation reflecting conditions at the time the contracts were entered. The record in that Docket limited consideration in two ways. First, the supporting analysis questioned whether the contracts were prudent when entered and thus sought a basis for imputation consistent with the costs of providing service known to that Company at the time. Since this cost was higher than contract rates, imputation was approved. Second, the only measure of cost proposed as the basis for imputation was the Company's avoided cost.

Neither of these limitations arise in the present Docket. Here, the imputation argument neither rests on a question of prudence nor is avoided cost the proposed basis for it. The prior Docket must also be distinguished in another important way. The applicability of the imputation decision in Docket No. 99-035-10 was qualified to that Docket alone. The Commission had found the record insufficient to resolve issues completely, in particular those involving aspects of risk. For this reason, a task force, consisting of the Company and the parties, was formed as the vehicle for further analysis. While the task force was meeting, however, the Company filed its Application in the present Docket, leaving the parties to address wholesale contracting issues in testimony as they saw fit. But before the task force concluded, participants recalled that the Commission's December 7, 1990 Report and Order in PacifiCorp general rate case Docket No. 90-035-06 adopted criteria for regulatory treatment of long-term wholesale sales contracts ("the 1990 criteria").

In the present Docket, the Division and the Committee propose to impute revenues to a group of contracts based upon the 1990 criteria. UAE/Nucor proposes imputation to selected contracts based on the Company's test-year short-term firm purchase price. The Company opposes imputation, arguing that its wholesale market transactions, including long-term firm wholesale sale contracts, have been prudently undertaken for the utility purpose of balancing firm retail loads and system resources. Should the Commission conclude that imputation is necessary, the Company argues that the proper basis for it is contemporaneous avoided cost, as applied in Docket No. 99-035-10.

The parties state that their proposals do not arise from a claim of imprudent contracting, but are based on the retail customer protection purpose of the 1990 criteria. This distinguishes their current proposals from those of Docket No. 99-035-10. We therefore begin by examining the applicability of the 1990 criteria.

The context in which the criteria arose for consideration in Docket No. 90-035-06 was a PacifiCorp proposal to eliminate an energy balancing account and to begin employing a normalized calculation of net power costs, using the PD/Mac model, for ratemaking purposes. Company testimony indicates that its intent thereby was to stabilize prices retail customers pay for service and to place both the risk of and the responsibility for managing net power costs on the Company itself. A further aspect of the proposal was to accord revenue credit treatment to long-term firm wholesale sales contracts. Revenue credit treatment means that the costs of serving these contracts are not identified or apportioned to wholesale customers. Instead, the costs are included in retail revenue requirement, to be recovered from retail customers. Likewise, the revenues produced by the wholesale contracts are also included in retail revenue requirement and are credited against these costs. These proposals were adopted as an outcome of that Docket.

Parties were concerned revenue credit treatment would expose retail customers to unwarranted risk. When the Company enters wholesale contracts at prices less than the fully embedded costs of serving them, revenue credit treatment means retail customers will be burdened. If those contracts serve the utility purpose of balancing firm retail loads with Company resources, as for example in the event of a temporary surplus of resources above load, and the contracts cover incremental cost and contribute to fixed-cost recovery, the burden may be justified. It appears this explanation was accepted, particularly given a Company argument that it had received approval from the Federal Energy Regulatory Commission to price such contracts at the average cost of a pool of resources consisting of the Company's most expensive thermal units. Thus, the Company had testified, at a future point the contract price would be higher than embedded cost and benefit would inure to retail ratepayers. Therefore, over the life of the contract, retail ratepayers would not be exposed to unwarranted risk.

Parties, however, remained concerned that the revenue credit approach could expose retail customers to significant risk because, for example, regulatory oversight would be diminished and the cost consequences of errors in forecasting, planning, or managing total Company load and resource requirements could fall to retail ratepayers. To manage this risk, the parties, including the Company, agreed the 1990 criteria would be appropriate. The criteria were proposed by them and adopted by the Commission.[(7)]

During a second phase of the 1990 Docket, a modification of criterion 4 (d) was proposed: "The contract either terminates, or covers full embedded costs by the time any new production investment is required to provide service to system loads." It was not adopted, but the Commission did accept a stipulation to establish a task force to further examine wholesale contracting. On April 13, 1993, the task force tendered a report to the Commission containing a new modification of criterion 4 (d): "Pricing shall be structured such that over the life of the contract retail revenue requirement will be protected from increases resulting from resource acquisitions needed to serve the wholesale contract." There is no evidence this modification was adopted by the Commission.

The purpose of the 1990 criteria and the proposed refinement of criterion 4 (d) is clear. Retail ratepayers are to be protected from the risks of the Company's long-term wholesale sales activity. Under the criteria, if the Company entered long-term firm wholesale sales contracts, it could not assume they would be accorded revenue credit treatment for ratemaking purposes unless and until the Commission so ruled. The Company entered into a number of these contracts, particularly in the period 1996 through 1998. Regulatory approval for revenue credit treatment of them was not sought. The record also shows that, without notice to this Commission, the Company had at about the same time abandoned the pool pricing concept.

We conclude that the 1990 criteria adopted by this Commission remain the applicable regulatory policy. The decisions reached in Docket No. 99-035-10 do not displace it. Those decisions are based on the record established in and meet the purposes of that Docket alone, as the Report and Order itself states. We disagree with the Company's suggestion that failure to apply the criteria in the interim may have rendered them void and as well its argument that a decision to apply certain of the criteria but not all them in the present Docket would be wrong. Under *Salt Lake Citizens Congress v. Mountain States Telephone and Telegraph Co.,* 846 P.2d 1245 (Utah), the criteria are applicable until the Commission alters them subsequently and on this record the Commission does not alter them. These criteria have not been applied previously because the Company did not seek regulatory approval for the contracts it entered after 1995. In fact, there is no record that the Company has ever sought such approval after the 1990 Docket wherein the criteria were adopted.

This decision means that the basis for the imputation here, contrary to the Company's assertion, is not whether the contracts were prudent when entered, but rather what is required to protect retail ratepayers. The Company therefore is also in error to insist the prior Docket's use of avoided costs for imputation is the only appropriate basis for it.

The Company has two substantive arguments against imputation. In the first, it calculates a benefit to retail ratepayers from revenue credit treatment of contracts in the amount of $1.3 billion. We find two reasons, however, that this claim does not withstand scrutiny. As a comparison between the revenues received from the contracts at long-term firm prices and what might have been received if the sales instead had been short term at short-term prices, it has an unacceptable basis. The Company itself acknowledges that a purely short-term sales approach would be imprudent. It is also true that the risk and other characteristics of the long-term and short-term market transactions are different. Second, a benefit cannot legitimately be claimed without reference to expenditures required to obtain it. Here, the costs of serving long-term firm wholesale sales contracts are entirely borne by retail ratepayers. There is no acceptable measure of this cost burden on the record. The Division states, and we agree, that the basis for measuring such costs would be a properly constituted wholesale jurisdiction. The Company offered to file its version of such a jurisdiction, but as this was at the eleventh hour and no party could have examined it, it was not accepted. An acceptable analysis would show, in a long-term context, the size and timing of resource additions which minimize retail cost of service, and the consequent need to use long-term firm wholesale sales contracts to achieve a balance of firm retail load and resources. Such a cost - benefit analysis is not present in this Docket. We conclude therefore that the $1.3 billion benefit is without foundation and cannot be accepted.

The Company also makes the substantive claim that imputation is inappropriate because its wholesale market activity, including long-term wholesales sales, has been undertaken to balance firm retail loads and resources, and because, contrary to the position of the parties, long-term firm wholesale sales are not served from short-term firm purchases. Were these suppositions correct, the load and resource data filed in this Docket would show the system to be in balance; that is, a requirement to serve total load, both firm retail and firm wholesale, would not reveal the purchase of an excess short-term firm and non-firm supply.

In the Company's filed net power cost study, there are, on an annual basis, 52.9 million MWh of firm retail load and 14.1 million MWh of long-term firm wholesale sales, for a total load of 67.0 million MWh. On the resource side, based on the Company's position, thermal and hydro generation totals 53.5 million MWh; to this is added 9.4 million MWh of long-term firm purchases, for a total of 62.9 million MWh. The long-term firm resources necessary to serve long-term firm loads are deficient in the amount of 4.1 million MWh, requiring the Company to enter into short-term firm and non-firm transactions to overcome it. The data do reveal, however, that the Company's thermal and hydro resources are sufficient, on an annual basis, to serve firm retail load. It is the inclusion of long-term firm wholesale sales transactions that requires the Company to engage in short-term purchases to meet its total firm load obligations. This conclusion follows even with recognition of the Company's argument that it engages in back-to-back short-term purchases and sales and undertakes such transactions to displace its own generation when it makes economic sense to do so.

Moreover, the record does not contain a complete analysis of the balance of resources and loads at times of system peak. The only evidence on this subject was introduced by the Division for the time of summer coincident peak. This analysis shows that the Company's long-term resources, including long-term firm purchases, are sufficient to serve firm retail load but insufficient to serve the total of firm retail and long-term firm wholesale sales loads. Long-term firm loads and resources are not in balance. The result is that the Company must undertake short-term firm purchases to meet its total firm peak load obligation in the summer.

The parties argue that reliance on the short-term market to meet total load requirements exposes retail customers to the risk of the kind of price increases that occurred during the test year. While the data does show, as the Company states, that the net excess of short-term firm purchases over short-term firm sales, that is, 2.2 million MWh, is a small percent of total resources, it is associated with large absolute dollars. In addition to the excess of short-term purchases over sales, to balance long-term firm loads and resources, given our decisions, it is necessary to make non-firm purchases in excess of sales in the amount of 2.3 million MWh. This is the consequence of relying on wholesale markets to balance long-term firm loads and resources which under Company proposals the firm retail ratepayer alone would bear.

We reject the Company's position. Firm retail load is not the sole source of the Company's load and resource imbalance nor the management decision to rely on short-term firm and non-firm markets to resolve it. Given our decisions above with respect to other Company arguments, we conclude that imputation of revenues to long-term firm wholesale sales contracts must occur to, as the purpose of the 1990 criteria reveals, protect retail ratepayers from the consequences of bearing unwarranted risk. Record evidence supports the UAE/Nucor premise that during or shortly after 1995 PacifiCorp adopted a business strategy emphasizing participation, independent of its obligation to serve native retail load, in wholesale market activity, and sought to position the Company there to capitalize on its view of a future restructured electric industry. Thus, long-term firm wholesale sales, which had been a small and quite stable portion of total load and a source of load and resource balancing, became a means to other business ends, reaching 54 percent of total load by 1997. It is impossible to conclude other than that the data belies the Company's assertion in this Docket that it always used wholesale transactions for no purpose but to balance load and resources or to reduce cost of service, either with short-term arbitrage transactions or by engaging in short-term purchases to back off more expensive thermal generation. The point is that in entering the contracts to an extent not related simply to the public utility purpose of balancing firm retail load with resources but far beyond such a requirement, the Company exposed ratepayers to substantial risk having little to do with a public utility's obligation to serve.

The Division asks the Commission to apply the 1990 criteria and to impute revenues to contracts that are at least halfway through the contract term and priced below the embedded cost of generation and transmission. This is done to meet the criterion that "after a short time" contracts are to cover embedded cost. That cost, based on the filed cost-of-service study, the rate of return adopted herein, an adjustment for losses, and other factors in its final position, the Division calculates at $33.72 per MWh. Revenues are computed at this amount for the selected set of contracts. Although the criteria also require the contracts to cover marginal cost and to make a contribution to fixed cost recovery, the Division argues embedded cost is appropriate for the purpose here. Test-year marginal cost is greater than embedded cost, but using marginal cost would result in a larger imputation than the Division believes necessary to mitigate the harm the contracts cause retail ratepayers.

Acknowledging the choice of marginal or embedded cost has no objective basis, the Division seeks to balance the interests of ratepayers and shareholders by choosing embedded costs. As the Division calculates the result, the use of embedded cost evenly shares the cost of serving the long-term firm wholesale sales contracts between ratepayers and shareholders. Stated differently, the Division argues shareholders bear responsibility for some though not all of the increase in net power costs recorded in this Docket; a 50 - 50 sharing, though a matter of judgment, appropriately accomplishes this objective. Were the imputation to be based on marginal costs in today's test-year circumstances, it would be of much greater magnitude. The revenue imputation advocated by the Division is $63.2 million for the total Company; $23.4 million for the Utah jurisdiction.

A revenue imputation the Committee advocates similarly cites the 1990 criteria. The Committee asserts that had the Company sought revenue credit treatment for contracts, regulatory approval would not have been granted because, at the time, the contracts covered neither incremental cost, that is, the costs of short-term firm purchases required to serve them, nor embedded cost. Accordingly, the Committee seeks an imputation of revenues based on current short-term market cost so that the revenues associated with the contracts adequately cover the costs of serving them. At the end of the proceeding, given developments with respect to the Deseret contract, the termination of two WAPA contracts, and an adjustment to the revenues for the power sold at "super peak" hours to Citizens Power, the Committee advocates revenue imputation for nine contracts that it determines do not meet the 1990 criteria. The Committee chooses a more select group of contracts than the Division. The Committee selects contracts for imputation which fail to cover approximately 60 percent of embedded costs. On a total Company basis, the recommended imputation is approximately $83 million; for the Utah jurisdiction, $30.77 million.

The Committee also asserts that load losses associated with the contracts are inappropriately assigned by the Company to the Utah jurisdiction, adding as much as five percent to Utah's peak demand and energy responsibility. The Committee believes the amount of this misallocation is $22.8 million. A task force should be formed, the Committee recommends, to study the issue. The Division believes this warrants investigation, but rather than a task force, it recommends the Commission require the Company to file a study of losses. We will require the Company to file this study as soon as practicable, but withhold judgment whether a task force will be necessary.

UAE/Nucor identifies six long-term firm wholesale sales contracts that it asserts were ill conceived when the Company entered into them, that is, they are said to result from a failed business strategy that sought other than regulated utility ends. We have relied in part on this characterization of Company behavior in reaching our decision that revenue imputation is necessary. That advocated by UAE/Nucor to prevent retail ratepayers from bearing the losses associated with these contracts, using the actual short-term firm prices filed by the Company, is $75.6 million for the total Company and $28.1 million for the Utah jurisdiction.

We particularly note that each party selects a subset of contracts for revenue imputation. Rather than arguing for an imputation of revenues covering each and every long-term firm wholesale sales contract, the selection results in a sharing of the cost burden between shareholders and ratepayers. Thus, UAE/Nucor testifies that a much larger imputation would have resulted had it imputed revenue to ten additional contracts it reviewed that PacifiCorp entered into since 1995. The Committee selects a group of contracts for imputation that it feels is significantly below embedded costs. The Division's choice rests both on its application of the criteria to select the contracts and the deliberate use of embedded rather than marginal costs as the imputation basis. We believe that the Division's use of embedded costs is appropriate and reasonable. On this record we conclude that revenue should be imputed to contracts that were entered into after 1995, when the Company changed its wholesale sales strategy, and to those contracts that are substantially below embedded costs. Hence we combine the Committee's selection of contracts subject to imputation with the Division's embedded cost adjustment.

We summarize the effects on net power costs of our decisions, and compare the results to prior periods. This information is provided in the tables below.

Table 1: System Net Power Cost Study Results ($Million)

	1997 **Actual**	**1997** **Stip'd**	**1998** **Actual**	**1998** **Adjusted**	**10/99-9/00** **Actual**	**10/99-9/00** **Adjusted**
Fuel Expense	481.891	477.276	521.824	491.860	491.275	442.700
Purchased Power Expense	1,239.443	938.433	1,100.013	1,008.514	1,381.317	1,462.535
Wheeling Expense	70.519	72.412	74.244	74.823	71.891	75.669
Power Costs	**1,791.853**	**1,488.122**	**1,696.081**	**1,575.197**	**1,944.483**	**1,980.904**
less Sales for Resale Revenue	(1,421.920)	(1,113.788)	(1,251.252)	(1,160.323)	(1,324.186)	(1,391.797)
Net Power Costs	**$369.933**	**$374.333**	**$444.829**	**$414.872**	**$620.297**	**$589.107**

Actual system net power costs in 1997 and 1998 totaled $370 million and $445 million respectively. For the test year, October 1999 to September 2000, actual net power costs totaled $620 million, an increase of nearly $175 million, or approximately 39.5 percent, relative to 1998. While fuel and wheeling expenses decreased in the test year relative to 1998, it is the larger increase in purchased power expense relative to the smaller increase in sales for resale revenue that accounts for the overall increase in actual net power costs in the test year relative to 1998. For comparison purposes, the amount of net power costs included in rates as a consequence of the last two general rate cases, Docket Nos. 97-035-01 and 99-035-10, are also shown in the table above. Net power costs, as adjusted by our decisions, totaled $589 million for the test year, October 1999 to September 2000.

Using the values of the System Generation (SG) allocation factor, 37.0634 percent, and the System Energy (SE) allocation factor, 36.9026 percent, accepted for use in Utah in this test year, the share of net power costs allocated to Utah are presented in the table below.

Table 2: Utah-Allocated Share of System Net Power Costs ($Million)

	1997 **Actual**	**1997** **Stip'd**	**1998** **Actual**	**1998** **Adjusted**	**10/99-9/00** **Actual**	**10/99-9/00** **Adjusted**
Fuel Expense	160.922	159.381	180.732	170.354	181.293	163.368
Purchased Power Expense	408.841	309.105	376.689	345.132	511.725	541.742
Wheeling Expense	23.229	23.847	25.385	25.599	26.640	28.040
Power Cost	**592.992**	**492.333**	**582.806**	**541.086**	**719.657**	**733.149**
less Sales for Resale Revenue	(468.259)	(366.273)	(427.843)	(396.487)	(490.722)	(515.741)
Net Power Cost	**$124.733**	**$126.059**	**$154.963**	**$144.599**	**$228.935**	**$217.408**
Adjustment to Actual		**1.327**		**($10.364)**		**($11.527)**
Megawatt Hours (million)		13.801		14.235		16.064
Average Cost ($NPC/Mwh)		$9.1339		$10.1579		$13.5336
Percent Change from Prior Yr				**11.2%**		**33.2%**

In 1998, actual net power costs allocated to Utah were $155 million. In the test year, actual net power costs allocated to Utah are $229 million, an increase of $74 million, or approximately 48 percent. Again, this increase is due to the larger increase in purchased power expense relative to the smaller increase in sales for resale revenue. On an adjusted basis, net power costs allocated to Utah were $145 million in 1998 and $217 million in the test year. Since the number of firm megawatt hours in Utah generally increased by almost 13 percent from 1998 to the test year, a useful comparison is the change in average cost. Relative to the average net power costs included in current Utah rates as a consequence of Docket No. 99-035-10, the increase in average net power costs as a result of our decisions is 33.2 percent.

DEMAND-SIDE MANAGEMENT

The UEO, citing its testimony and supporting exhibits, recommends that the Commission pursue a variety of actions to promote demand-side resources also known as demand-side management (DSM). First, UEO recommends that the Company act expeditiously to implement DSM initiatives proposed by its expert witness Dr. Nicholls. Dr. Nicholls is the lead author of a Tellus Institute report, "*An Economic Analysis of Achievable New Demand-side Management Opportunities in Utah",* submitted to the Energy Efficiency Advisory Group, a task force established by the Commission in the last rate case. The report indicates that an enormous potential of cost-effective, achievable demand side resources lies untapped in PacifiCorp's Utah service territory.

The UEO recommends the Commission order the Company to expand its recent June 26th DSM tariff filings to include additional cost-effective demand-side program resources as recommended in Dr. Nicholls's testimony. The new filings should include a suite of DSM initiatives that includes residential, commercial and industrial programs. Specifically, the UEO recommends the Company implement $35 million of new DSM programs within the next year and the continuation of such expenditures as they prove cost-effective. The UEO recommends a multi-year program costing approximately $190 million with a total resource cost of $370 million. The estimated energy savings cited in the report approach $1.44 billion in present value terms, with a net benefit of $1.08 billion. The analysis indicates that average rates could be reduced by $132 million over the 24 year period associated with the life of the measures. These projections are based on a myriad of assumptions regarding gas costs, PacifiCorp rates, and estimated savings and penetration rates of the measures. However, the results do not depend on savings associated with extremely high wholesale prices of the past year. The UEO maintains that additional benefits of DSM investment, though unquantified, will inure to Utah customers in terms of employment, income growth and environmental benefits.

The UEO also recommends the adoption of a cost recovery mechanism that allows the sharing of DSM savings between ratepayer and shareholder. They suggest a tariff rider as a possible mechanism with separate tariffs for each customer class to address equity issues. The tariff riders would be adjusted to true up any over or under collection of funds.

The UEO also recommends that the Commission direct the Company to design and file a net metering tariff for its Utah service territory based on the recommendations of the Energy Efficiency and Renewable Energy Task Force report submitted to the Commission in December 1999. Finally, the UEO recommends the Commission open a docket to explore the potential opportunities for distributed generation.

The Division recommends against increased DSM spending beyond what is currently approved by the Commission. Resource acquisition should be made within the context of the Company's integrated resource plan (IRP) which requires equal consideration of supply-side and demand-side resources. The Division recognizes the Tellus report as indicative of potentially cost-effective DSM programs but the report's assumptions have not been scrutinized, nor have various scenarios been tested. The Division argues that the tariff rider approach is problematic. It may violate Commission test year conventions and could face serious legal challenges associated with its implementation. The Division supports all DSM investment to the extent it is cost-effective.

The Committee recommends against approval of the DSM package proposed by the UEO until the DSM measures are fully analyzed in the RAMPP/IRP process. The Committee finds fault with the sharing mechanism of the UEO's cost recovery mechanism and states that rate treatment of DSM need not differ from supply-side treatment. The Committee recommends that the parties work collaboratively through the RAMPP process to develop energy conservation programs tailored to the new wholesale realities in the West. The Committee does not believe the Company should be ordered to develop DSM programs " (rather) if DSM is demonstrated to be the most cost-effective and reliable resource to meet increasing retail loads, then a utility would possibly face cost disallowances if it elected to avoid those investments to improve its bottom line." CCS-9R page 3

Large customers such as the UAE, Nucor, UIEC, as well as the USEA also recommend against Commission ordered increases in DSM programs without further study by parties in the Energy Efficiency Advisory Committee. The proposal is missing the critical detailed elements of design and implementation necessary to demonstrate its cost-effectiveness. Without such a demonstration, the economic benefits are speculative. The industrials cite equity concerns that must be addressed and argue that a tariff rider puts ratepayers at risk for a poorly run DSM program. They recommend that the proposal be referred to the advisory group for further analysis.

The Commission will not order the Company to propose new DSM programs at this time. The record is insufficient for us to make a definitive finding that the programs outlined in the Tellus report are the most cost-effective resources available to the Company. However, the Commission notes the findings of the report indicate that ratepayers could benefit from increased investment in DSM. The Company should evaluate each program and incorporate cost-effective demand-side resources in the next interim update of the IRP. The Commission is particularly interested in programs that can cut peak demand. Load control measures may prove particularly promising to cutting cost. Programs that have the potential to pass the Ratepayer Impact Test (RIM) and lead to lower rates for all customers should receive particular attention. The current IRP guidelines require that the Company bring forth the least-cost resources and implement them in a timely fashion.

The Commission notes that the Company has recently filed and received tariff approval for enhanced DSM programs. A deferred accounting order for these program expenditures is currently before us, thus we will defer a decision on the UEO's cost recovery proposal at this time. Testimony on the merits of the proposed cost recovery mechanism is contained in the spread portion of this rate case and can be addressed there.

The Commission is aware that the legislature is preparing legislation for the 2002 general session that will require that PacifiCorp offer its customers net metering, a process in which customers get credit for excess self generation returned to the grid. The Energy Efficiency and Renewable Task Force recommended that the Commission establish a net metering tariff. We generally support net metering and direct the Company to begin preparing a tariff and its network in order to accommodate net metering as soon as the proposed law becomes effective. Should the proposal not be enacted, we would consider requiring the Company to provide net metering. The Commission directs the ongoing Energy Efficiency Advisory Group to continue the study of distributive generation and ways that such resources can increase the reliability of the system and lower costs for participants and the system as a whole.

CONCLUSION

The impact of the issues resolved in the parties' stipulation we approved August 17, 2001, in conjunction with the net power cost issues we resolve above is $40,573,755.

ORDER

On February 2, 2001, we granted PacifiCorp a $70 million interim rate increase pending final disposition of this Docket. By this order we establish an increase in PacifiCorp's revenue requirement of $40,573,755. Any amount collected over this increase since February would be subject to refund. Under UCA 54-7-12 (3) (b), and for the sake of administrative cost savings and simplicity, we will maintain rates at current levels until we issue a final order in the second phase of this proceeding following the hearings in October.

For the first time in many years, we bifurcated this rate proceeding and will take testimony on cost of service and rate spread among customer classes October 1 - 5, 2001. We order the parties to provide a rate design proposal which uses the revenue requirement determined in this Order in their September 21, 2001 surrebuttal testimony.

Within 30 days of the issuance of this order, an aggrieved party may file a written request for review by the Commission. If such request is denied in writing within 20 days, or deemed denied by failure to grant review, the aggrieved party then has 30 days following such denial within which to petition the Supreme Court for review.

Dated at Salt Lake City, Utah, this 10th day of September, 2001

/s/ Stephen F. Mecham, Chairman

/s/ Constance B. White, Commissioner

/s/ Richard M. Campbell, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

1. On March 16, 2001, these additional customers were added to the group, without opposition: Alliant Aerospace Propulsion Company, Central Valley Water Reclamation District, Chevron USA, Geneva Steel, and S F Phosphates.

2. During these proceedings, the Office of Energy and Resource Planning was renamed the Utah Energy Office (hereafter Utah Energy Office or UEO).

3. Public witness appearances on the case generally and on the revenue requirement issues were made on August 1, 2001.

4. Public witness appearances on the cost of service and rate design issues is scheduled for October 3, 2001.

5. The Land and Water Fund and the Utah Energy Office addressed or raised issues relating to conservation of electricity efforts associated with the general rate case.

6. The group of contracts at issue include Pacific Northwest Generating Cooperative, Okanogan, Clark-FiberWeb, Clark-WaferTech, Cowlitz-BHP, Black Hills Storage, San Diego Gas & Electric, Springfield II, Hinson-Columbia Falls Aluminum Company, Clark, Cheyenne, Redding, Citizens Power, WAPA (I), WAPA II.

7. The criteria are: (1) All existing firm Utah FERC wholesale and wheeling business taking service prior to the merger be excluded from the Utah jurisdiction and included in a FERC jurisdiction for reports and filings in Utah. New firm sales and wheeling at tariffed, fully-embedded rates would also be included in the FERC jurisdiction. (2) Nonfirm sales for resale and wheeling, and long term contracts not covering fully embedded costs where service is begun on or after the merger (Sierra and Puget included), would be treated as revenue credits, after approval of the contracts by the Utah Public Service Commission. (3) In the event that costs are imposed on UP&L by the FERC Order No. 318 that are not fully recovered from those imposing the costs, then those contracts would also be included in the proposed FERC jurisdiction. (4) Any long term contract proposed to be treated as a revenue credit be filed with the Utah Public Service Commission for subsequent approval of that revenue credit status. That filing would have to include the necessary information to verify that: (a) the sales couldn't have been made at rates based on full embedded costs; (b) the contract covers marginal cost; (c) the contract make a contribution to fixed costs; and (d) after a short time, the contract either terminates, or covers full embedded costs. (As cited in DPU Ex. 8.0, p. 9.)