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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))	Docket No. 99-035-10 POST-HEARING BRIEF OF THE LARGE CUSTOMER GROUP

Introduction

Calendar year 1998 was an extraordinary and tumultuous year for PacifiCorp--and for its customers. By its own admissions, PacifiCorp was "unfocused" on its regulated services during most of 1998 [Tr., p.32, ll.16-22 (Dalley); p.48 l.10-p.49 l.13(Dalley)]--in large part because it was focused on expanding itself into a major player in both the national and international energy arenas. It was a year that saw PacifiCorp's ambitious and expansionist plans reach a zenith, and then crumble. Global acquisitions that had been pursued with vigor were abandoned. PacifiCorp's wholesale sales nearly eclipsed its retail sales. PacifiCorp suffered massive losses in futures trading. Management eventually acknowledged its lack of attention to its regulated activities and committed to "refocus" on those activities. Management was replaced and the company was placed on the auction block and ultimately sold to an international utility. All during 1998. It should thus come as no surprise that PacifiCorp's captive customers look with skepticism at the request of the new owner of PacifiCorp for a massive rate increase based on an historic test year that spans all of the extraordinary events of 1998.

In its prefiled testimony, the LCG sponsored several significant adjustments to PacifiCorp's net power costs. It took specific positions on a number of other revenue requirement issues raised by PacifiCorp and other parties. The LCG also sponsored testimony on cost of service, rate spread and rate design issues. Finally, it submitted testimony on proposals to implement a System Benefits Charge and on standards for approval of special contracts. In this memorandum, the LCG will present a brief summary of it positions on these issues.

I. <u>NET POWER COSTS</u>

A. *Introduction*

Calculating net power costs--costs incurred by PacifiCorp in generating and purchasing power, minus a credit for revenues from wholesale transactions--is not a conceptually difficult process. Because of dramatic variations in water conditions, however, electric generation can vary by as much as 50% from year to year in some areas. It is thus not uncommon for utilities to attempt to "normalize" hydro conditions, although that process can be very complex.

Calendar year 1998 was essentially a "normal" water year. [Tr., p.647, ll.1-9 (Widmer); p.1208 l.13-p.1029 l.1(Wilson)]. PacifiCorp uses the term "normalization" to describe a series of adjustments that it made to its actual 1998 results. Its "normalization" procedures are extreme, opaque and illogical. At virtually every step, PacifiCorp's procedures are designed to reduce revenues from wholesale sales and increase net power costs. [Tr., p.1209, ll.2-21 (Wilson)]. Despite a normal water year, PacifiCorp's proposed "normalization" adjustments produce astounding and illogical results, all designed to increase net power costs and mask the effects of its "unfocused" year. PacifiCorp's retrospective normalization projections suggest that, if

PacifiCorp had 1998 to do over again, its costs would be much higher, its sales would be much lower, and the prices it receives for sales would be much worse that they actually were.

Because of the sheer magnitude of PacifiCorp's wholesale transactions in 1998, it is particularly critical that net power costs, including the wholesale revenue credit, be determined accurately and fairly. However, despite the incredible amount of money affected by the net power cost calculations and the significant resulting impacts on PacifiCorp and its customers, PacifiCorp elects to use sadly outdated and unreliable hardware and software to make its retrospective "predictions" of "normalized" net power costs. The models, inputs and processes used by PacifiCorp in its misguided attempt to predict the past are riddled with unsupported judgments, data that has not been supplied or supported, erroneous and outdated computer code and numerous other shortcomings. PacifiCorp's amateurish, unsupported and unreliable means of estimating its single largest expense items are shocking and disturbing. The bottom-line results suggested by the model--that sales are declining in a massively expanding market--are counter-intuitive and unreasonable. PacifiCorp has, in essence, "forecasted" $259 million less in 1998 revenues than it actually received. Its retrospective forecast, done in the name of "normalization," would provide PacifiCorp with a tremendous windfall at the expense of its customers.

PacifiCorp has failed to satisfy its burden to establish reasonable net power costs for purposes of this rate case. PacifiCorp's net power cost testimony was challenged by witnesses for the Division, the Committee and the LCG. Although the parties addressed various perceived problems in different ways, all agreed that substantive adjustments are necessary before PacifiCorp's net power cost calculations could be considered reasonable.

The Commission should largely reject PacifiCorp's net power costs calculations. For purposes of this case, the Commission should utilize PacifiCorp's actual 1998 short-term sales and revenues as an offset to power costs, correct PacifiCorp's unreasonable assumption that the quantity of power available in the market will not affect prices, and normalize the effects of significant one-time losses experienced in the summary of 1998. PacifiCorp's net power costs, system-wide, should be set at $306 million, rather than $430.2 as argued by PacifiCorp. Looking forward, the Commission should instruct PacifiCorp that it will no longer accept net power costs calculations based on the obsolete, error-riddled PD/Mac model, and should direct PacifiCorp, in consultation and cooperation with the Division, Committee and other interested parties, to develop a reasonable and verifiable means of calculating net power costs.

PacifiCorp developed the prices and quantities used in determining the wholesale sales credit through a complex and bizarre series of undocumented spreadsheets. For example, Utah's short term firm sales for resale are based on 1998 forecasted prices taken from the Impact model, which states that its output is in 1997 real dollars. Those figures are then adjusted to an undocumented monthly shape from 1999, and applied to an average of 1997 and 1998 quantities. PacifiCorp's model mangles the concept of an historical test year. PacifiCorp has "lost" workpapers supporting many of its adjustments. For example, there is no documentation for the results of PacifiCorp's "FORWPRIC" model--PacifiCorp states that it is simply missing. Incredibly, PacifiCorp asks the Commission to accept the calculations and inputs notwithstanding the lack of documentation. PacifiCorp has offered no valid reason for ignoring actual sales data in favor of hypothetical data.

B. *Sales for Resale Adjustments*

1. Inflation Error

The results of the Impact model are stated to be in real 1997 dollars. [Tr., p.664, ll.1-4 (Widmer)]. PacifiCorp witness Widmer claimed that, although the Impact results state in twenty-four separate places that they are in 1997 real dollars, they are mere labeling errors and the numbers are actually in 1998 dollars. PacifiCorp refused to provide documentation for the Impact model or the sources of Impact data. It is thus not possible to know the truth. Because PacifiCorp has not adequately rebutted its own documentation, if the results of the Impact model are used, an adjustment for inflation of 1.6% should be added to the values from the Impact model. Instead, however, the LCG recommends the use of actual 1998 sales data.

2. Capacity Factor Error

PacifiCorp weighted on-peak and off-peak pricing by 65%. Despite repeated requests, Pacific refused to provide any justification for this value. As with most of its arguments relating to PD/Mac, PacifiCorp simply states, without support, that 65% is the correct value. [Tr., p.664, ll.14-21 (Widmer)]. A 65% weighting factor is neither logical nor appropriate. A prudent operator takes advantage of its ability to factor off-peak energy into on-peak energy. An assumption that only 65% of available energy is sold on-peak presumes a flat product. It would not be appropriate to assume that PacifiCorp will do a poor job of marketing its power. The hourly sale and purchase data provided by PacifiCorp shows that its actual load factor was 71%. If PacifiCorp's “projected” numbers are used, they should be corrected to this load factor, based on actual evidence rather than unsubstantiated statements. The result would be to increase PacifiCorp's price estimates between 0.6 to 1.0 mill. Again, however, rather than making these corrections to the “projected” sales data, the LCG suggests the use of actual sales data.

3 Short Term Sales

As explained above, PacifiCorp employed a set of arbitrary, unsupported and complicated adjustments designed to reduce its average wholesale revenues below 1998 market levels; indeed, below the actual prices it received. The corrections employ an undocumented seasonal shape from 1999 and use 1998 and 1999 forecasted values from a second computer model that uses assumptions inconsistent with those used by PD/Mac. Actual 1998 wholesale prices were approximately 1 mill higher on average than the numbers stemming from PacifiCorp's retrospective "forecast." None of these complicated steps is necessary or appropriate, given that actual data is readily available. There is no valid reason not to use actual data for both quantities and prices of 1998 wholesale sales.

McCullough's first recommended adjustment is to return sales-for-resale revenues to actual 1998 levels. This adjustment, after correcting a mathematical error identified by Mr. Widmer, decreases PacifiCorp's claimed net power costs by $ 65.5 million dollars on a system-wise basis--$23.34 million for Utah--for calendar year 1998. Committee witness Falkenberg and Division Witness Wilson propose to use actual market prices for short term firm sales and purchases for an adjustment of $2.3 million. This adjustment is a good first step, but it fails to also make the correction for actual short term sales quantities. The LCG recommends the use of both actual prices and actual quantities for 1998 wholesale sales.

In objecting to this adjustment, Mr. Widmer claims that Mr. McCullough has mixed actual data and modeled data. His criticism is strange, given that the results sponsored by Mr. Widmer include an extreme hodge-podge of actual and modeled data and results. [E.g., Tr., p.643, l.24-p.650 l.24 (Falkenberg)]. Indeed, about sixty percent of the wholesale transactions "modeled" by PD/Mac use actual data, and about thirty percent of the fuel contracts. [Tr., p.1554, l.15-p.1555 l.8 (Falkenberg)]. PacifiCorp's approach is to eliminate actual numbers that it does not like and replace them with unsupported and illogical assumptions and calculations designed to produce higher net power costs. Particularly given the use of an historical test year, it is fully appropriate to use actual historical prices and quantities for short term sales.

Mr. McCullough utilized PD/Mac to generate the energy needed to meet actual 1998 sales levels. Such an approach is fair and reasonable. Properly used, PD/Mac is happy to find energy for such sales, and it indicates a substantial profit when it does so. However, given the odd logic of PD/Mac, it uses available energy until it is forced to purchase emergency power to meet sales. PacifiCorp makes the unreasonable assumption, without offering any analysis or study in support, [Tr., p.671, ll.8-15 (Widmer)], that this “emergency power” will cost 50 mills in all months. In fact, market prices for blocks of power in 1998 were available at much lower levels. PacifiCorp did not actually purchase such blocks of energy in 1998 because it elected to “go short,” and got caught by the extreme pricing changes caused by the California Power Exchange and the California Independent System Operator. Using an assumption of prudent management, however, the “emergency” purchases used by the model should be adjusted, as suggested by Mr. McCullough, to be consistent with regional pricing.

Mr. Widmer objects to Mr. McCullough's use of the PD/Mac model to estimate short term firm purchase costs. He claims that PacifiCorp does not purchase secondary energy to support short term sales and that PD/Mac power costs are not comparable to actual historical results. Curiously, despite going to great lengths to derive energy prices to meet loads in 1998 with PD/Mac, he then argues that these prices are not consistent with PD/Mac loads. PacifiCorp could just as easily have gone long in the summer of 1998, in which case actual results would have been very close to those assumed by Mr. McCullough. Despite a nearly 75% increase in short term firm and spot market prices from 1997 to 1998, [Tr., p.663, ll.8-11 (Widmer)], PacifiCorp's 1998 net power costs remained extremely high. Under the circumstances of this case, the Impact model, which includes a capacity component, is a reasonable means of meeting PacifiCorp's firm 1998 sales. In fact, the prices supplied by the Impact model are higher than many year-long transactions that occurred in late 1997 and early 1998. Mr. Widmer's objections to the use of his own models for these purposes is unpersuasive.

PacifiCorp had an excellent year for wholesale sales in 1998. Total volumes increased enormously. However, it did not correctly predict the impact of California's new market structure and thus failed to protect itself against the higher price of "going short." It also sold power at lower prices than it should have during the summer months. Mr. McCullough's adjustments respond to both errors. The intent is not to punish PacifiCorp, but rather to avoid setting rates on the assumption that the same mistakes will be repeated.

Mr. Widmer's final response to the proposed adjustments to short term sales is to make the preposterous suggestion that short term sales be removed completely from the calculation of net power costs. In the real world, sales for resale and prices are increasing. PacifiCorp is in an excellent competitive position. PacifiCorp's assets must be applied for the beneficial use of the captive customers who bear the risks. PacifiCorp should not be permitted to either confiscate or mismanage these assets or the benefits that flow from them.

4. Impact of Quantity on Prices

As used by PacifiCorp in this case, PD/Mac did all of its 50-water-year calculations based on the astounding and illogical assumption that water conditions do not affect spot market prices. Rather, PacifiCorp imposes a single spot price on its model for every water year. This assumption is particularly illogical given that PacifiCorp has gone to such great lengths to "normalize" quantities for differing water conditions.

Every witness who addressed this issue--even Mr. Widmer--agreed that water levels impact spot prices. Mr. Widmer nevertheless attempts to justify the illogical assumption inherent in his use of PD/Mac by arguing that water levels do not impact prices as much as they did in the past. [Tr., p.643, ll.3-7 (Widmer); p.651, l.9-p.653 l.17 (Widmer)]. By making the assumption that prices remain the same regardless of water year conditions, PacifiCorp significantly increases its apparent net power costs whether the actual water year is good or poor.

Despite its archaic and obsolete nature, even PD/Mac has a feature that recognizes the indisputable correlation between quantity and cost. Unfortunately, however, the computer code designed to address this correlation was effectively "turned off" by PacifiCorp. The only explanation offered by Mr. Widmer is that this code has been turned off since the PacifiCorp/Utah Power merger. [Tr., p.1645 ll.1-5 (Widmer)]. The fact that PacifiCorp has systematically overstated its net power costs since the early 1990s is hardly a justification for continuing to do so now that the problem has been identified.

Mr. McCullough's second adjustment effectively "turns on" the PD/Mac code that permits prices to vary with quantity through the use of PacifiCorp's Impact model Not surprisingly, the Impact results confirm that a 10% increase in water flows in the Pacific Northwest leads to a reduction of about 6% in regional spot prices. These results are also consistent with actual data. By allowing prices to respond to quantity, PacifiCorp's system-wide net power costs are reduced by $26.89 million--$9.33 million in Utah.

Mr. Widmer claims that Mr. McCullough's calculations contain an error, but it attempting to “correct” this so-called error, Mr. Widmer made a nearly identical "error." Mr. Widmer's response does not demonstrate an error, but rather provides a dramatic example of problems inherent in PD/Mac. The “problems” discussed by Mr. Widmer reflect fundamental and inherent problems imbedded in PD/Mac; they are not related to Mr. McCullough's adjustment designed to inject a measure of reality into the price-quantity relationship. Mr. McCullough's corrections are fully consistent with PD/Mac’s calculations and results in other areas. Unless PD/Mac is rejected in total as a basis for setting net power costs, this adjustment to "turn on" the quantity-price variable should be made. To do otherwise would be to permit PacifiCorp to continue its systematic overstatement of net power costs.

5. Normalization of Summertime Pricing

Mr. McCullough’s final adjustment is to normalize summertime sales to remove the effects of a single significant change that occurred in 1998 power markets--the establishment of a new California market mechanism. PacifiCorp claims to adjust for unique events that have a substantive impact on power costs, but it failed to adjust for the one-time impact of the unforeseen 1998 summer price spikes caused by the California ISO and PX. Mr. McCullough's adjustment returns PacifiCorp's 1998 summer sales to profitability.

PacifiCorp's average 1998 profit on short term sales over short term purchases was 0.76 mills during the nine non-summer months. During the months of July, August, and September, the margin fell to -1.26 mills. PacifiCorp's short term sales during the three summer months totaled 7,973,446 MWh. By returning the three summer months to comparable profitability as the rest of the year, net power costs are reduced by $10.4 million system-wide, $3.61 million for Utah.

As usual, Mr. Widmer complains about everyone’s "normalization" adjustments other than his own. As used by PacifiCorp in this proceeding, normalization has a unique and self-serving meaning. For example, PacifiCorp “normalized” its sales data using numbers from 1997, 1998, and 1999, and it used undocumented “FORWPRIC” numbers from 1999 to “normalize” the load pattern of 1998 to the more extreme pattern of 1999. The fact that PacifiCorp’s management seriously misjudged the market in 1998 should not be used to punish ratepayers by forcing them to pay rates as if PacifiCorp will repeat the same mistake year after year, especially now that the summer price spike is well understood. PacifiCorp should not be rewarded for its errors or misjudgments. Assuming prudent management, PacifiCorp will not repeat the mistake of "going short" over the summer months.

C. *PD/Mac and Related Models*

PacifiCorp continues to use an outdated and confusing computer program that is difficult for others to effectively examine or understand. The program could easily be recast it in a more modern form using a Microsoft Excel program. Porting PD/Mac in to an Excel format would not necessarily produce better results than the existing PD/Mac, but updating the model for contemporary realities and market sophistications would then be much easier, and the ability of others to audit and examine the results would be greatly enhanced.

The number, scope and severity of problems discovered in using PD/Mac are alarming. The problems discovered by Mr. McCullough and others with PD/Mac include, but are not limited to, the following:

- Programming errors were discovered in the memory search routine "GetAOffset" resulting in random and unforeseeable errors.
- The program includes assumptions that are wildly at odds with reality and current practice.
- The model, which was created before 1980 and modified in the early 1990s, fails to recognize or take into account the 1992 Energy Policy Act, Order 888, or the other significant market changes of the last decade.
- The Long Term Intertie Access Policy Act, which is central to PD/Mac's logic in nearly every one of its subroutines, was repealed in 1996.

- The model continues to store water in response to rules implemented by BPA to serve Direct Service Industrial (DSI) customers, even though these rules were abandoned in 1995.
- Serious errors exist in the use of the hydro record within PD/Mac, including incorrect operating years and inconsistencies between the claimed source of data and the non-firm energy used in the model.
- The first half of 1978 is added to the latter half of 1929 to form one water year.
- PD/Mac uses a July-to-June operating year; the water year used in actual markets was changed to August-to-July in 1992; every single water year related calculation is off by one full month, causing serious errors in results.
- The origin of the hydro data is undocumented and unclear; Mr. Widmer was unable, on the stand, to identify the source of the data. [Tr., p.678, l.12-p.679, l.6 (Widmer)].
- If, as PacifiCorp suggests, the hydro data is from the 1996 BPA "White Book," that kind of use of White Book data is inappropriate and produces inaccurate results. The White Book does not even purport to be valid for such purposes. The data is based on earlier years and it is inconsistent with PD/Mac assumptions and the actual spot market.
- PD/Mac has moved much of the region's non-firm energy into May and June, so it reduces the amount of energy available for displacement for the rest of the year.
- The model assumes market restrictions that do not exist in reality. For example, it assumes non-existent market sharing mechanisms that reduce non-firm availability by 75.09%, and regional uses that improperly reduce the assumed availability of energy.
- The hydro data utilized by PD/Mac does not match the stated source, the water years have been incorrectly used, and the application of the information is inconsistent with the actual spot market that Pacific faced in 1998 and that it will face in the future.

- The energy used to displace public resources in the model is often larger than the resource to be displaced because PD/Mac programmers confused operating years (starting in July in PD/Mac) and calendar years in at least one subroutine.
- PacifiCorp's power cost data relies on models not in evidence, that PacifiCorp will not produce, and that have not been scrutinized by the Commission. [Tr., p.668, ll.4-13 (Widmer); p.715, l.22-p.716, l.12 (Widmer).
- PD/Mac and related models are very resistant to audit; the MCP model used for the first time this year is more complex, and has never been audited. [Tr., p.1549, l.25-p.1550, l.3; p.1568, l.25 - p.1569, l.14 (Falkenberg)].
- PacifiCorp makes unique use of a future market price forecasting model to "normalize" historic data. [Tr., p.1587, ll.3-12 (Falkenberg)].
- The Hayet/Falkenberg analysis of PD/Mac, done in conjunction with the 1997 rate case, observed that the program may become obsolete because of the rapid evolution of the industry, recommended conversion of the program to a PC platform rather than a Macintosh platform, and noted that a number of important input variables are still determined in a judgmental fashion. [Cross-Exam. Exh. # 45, at 29-32].

PacifiCorp’s response to these and other modeling errors and problems is the unsupported and illogical claim that none of them significantly affects model results. [E.g., Tr., p. 614, ll.12-17 (Widmer)].Time and time again, Mr. Widmer asserts, each time without documentation or proof, that the problems have been "fixed" or that they do not impact the results. For example, in response to the outdated LTIAP code, PacifiCorp claims to have run a “sensitivity analysis” to demonstrate the lack of impact. [Tr., p.656, l.21-p.657, l.3 (Widmer)].Of course, PacifiCorp did not supply or place in the record any workpapers or documentation of this so-called sensitivity analysis or how it reached its illogical conclusion that it has no impact. The claimed results of this sensitivity analysis are counter-intuitive; increasing the market for exports would clearly have an impact on net power costs, assuming a workable model that reasonably mimics the real world.

Similarly, after Mr. McCullough pointed out the improper and outdated storage of water for BPA's DSI customers, Mr. Widmer claimed that he had "fixed" the error, and once again proclaimed that it had no effect on results. [Tr., p.657, ll.8-15 (Widmer)]. Again, of course, PacifiCorp refused to provide information or documentation to confirm or disprove its "fix." [Id., p.657, ll. 16-22]. Unfortunately, the lack of documentation from PacifiCorp makes it very difficult to identify the precise impacts of the numerous PD/Mac errors and problems, either individually or cumulatively. PacifiCorp steadfastly refused to produce the workpapers and inputs necessary to determine the impact of these PD/Mac errors. As with nearly all of PacifiCorp's net power cost testimony and data responses, the "proof" is simply an offhand claim unburdened by documentation or proof. The one clear result of Mr. Widmer's responses to the numerous errors and problems identified by several witnesses with respect to his PD/Mac calculations is that, regardless of the error or problem, he can consistently "fix" it in a way that will increase net power costs even more. [E.g., Tr., p.615, ll.8-12; p. 652, l.21 - p.653, l.1; p.655, ll. 13-19; p.665, ll.2-11 (Widmer)]. At its core, this is perhaps the most damning witness to the fact that PacifiCorp's use of PD/Mac and related modeling is unreliable.

Ultimately, Mr. Widmer's defense of the embattled PD/Mac program is an inappropriate and unsupported reference to a so-called "backcast" allegedly performed by PacifiCorp. As usual, PacifiCorp did not introduce the so-called "backcast" into the record or supply it to the LCG in a manner that would permit analysis or comment on the record. The claimed "backcast" is unpersuasive, unverified and worthless. It cannot be relied upon for any purpose.

The purpose of "normalization" is to eliminate unique events that might bias power cost estimation. By this standard, PD/Mac needs badly to be "normalized." Much of the logic is out of date. Many of the market structures are no longer in use; some of them are no longer even legal. Data is undocumented and confusing. It is nothing short of remarkable that these critical and substantive net power cost calculations are done, by deliberate choice, on obsolete, inefficient and unreliable tools rather that readily-available, economical and superior alternatives. The Commission should simply reject PD/Mac as a power cost model on a going-forward basis. Mr. Widmer's desire to avoid spending a few thousands of dollars of ratepayer money to avoid replacing an outdated and unreliable computer program is simply not credible, particularly in light of PacifiCorp's obvious willingness to spend hundreds of millions of ratepayer dollars on the SAP program. The resistance is more easily explained by the fact that the results of the PD/Mac modeling for PacifiCorp are so consistently to its liking.

D. ***Confidentiality***

PacifiCorp characterized most of its net power cost material in the case as confidential, even though virtually none of it is properly confidential. Secrecy is easy to assert, but it makes little sense in connection with a model that attempts to predict the past. In fact, nearly all of the information would be available, at significant effort and cost, in public forums. By asserting confidentiality liberally, PacifiCorp makes open discussion, audit, and review much more difficult and expensive. As a regulated utility, PacifiCorp expects reimbursement from the ratepayers for its costs. Creating obstacles to a review of these costs only adds to the burdens borne by PacifiCorp's customers and gives PacifiCorp an unfair advantage in the regulatory process.

II. OTHER REVENUE REQUIREMENT ISSUES

Many of the Company's reported expenses were substantially higher in 1998 than in prior years, and even much higher than its own 1998 budget forecasts. A careful review of its revenue requirements is particularly critical in this case.

A. SAP-Related Expenses

Many of PacifiCorp's proposed adjustments are inextricably linked to its planned implementation of the SAP system. PacifiCorp's decision to implement SAP was made at a time and in a context in which it expected to grow into a major national player with a significant global presence. [Tr., p.403, ll.1-6 (Meier)]. Thereafter, that vision was abandoned but the decision to implement SAP was not revisited. On the current record, it cannot reasonably be determined that the SAP system was a prudent stand-alone decision for PacifiCorp's regulated activities. It was a massive investment--rivaling the cost of some power production facilities--yet it has not been adequately supported nor fully audited or evaluated. The LCG believes that a thorough audit of all SAP-related expenditures is essential before cost recovery should be allowed.

Whether or not the SAP expenses are first subjected to a thorough audit, the record in this case does not support the inclusion of any significant portion of SAP-related expenses in a 1998 historic test year. The SAP system was not used and useful on a company-wide basis until at least 1999. Beginning full amortization of SAP related expenses in a 1998 test year is thus inappropriate and would result in an improper mismatching of costs and benefits. No real 1998 benefits can properly be attributed to implementation of SAP. [E.g., Tr., p.407, l.14-p.416. l.18 (Meier)]. Because SAP was not rolled out for any type of general use within the company until 1999, most, if not all, of the SAP-related expenses are out-of-period adjustments. Amortization of SAP-related expenses should not begin in a rate case utilizing a 1998 historic test year. At most, only 5.3% of SAP-related costs otherwise allocable to test year 1998 should be considered for inclusion in this case, based on the percentage of potential users who actually used the system in 1998 (171/3200). [Tr., p.406, ll.14-24 (Meier)].

If any SAP-related cost recovery is permitted in this case, the costs must first be properly allocated between PacifiCorp's regulated and unregulated activities. The decision to implement SAP was clearly predicated on the company's anticipated regulated and unregulated activities and in anticipation of the utility's expansive plans. PacifiCorp, however, has allocated less than 2% of the SAP costs to unregulated activities, based on an after-the-fact analysis of the number of actual system users. It is not particularly surprising that the actual users are predominantly related to regulated activities, given the utility's significant change in plans that occurred after the decision to purchase SAP had been made. On the current record, the most appropriate basis for allocating any SAP-related costs is on the basis of PacifiCorp's revenues from regulated and unregulated activities in 1998. The only reasonable alternative is a prior audit designed, among other things, to identify the intended uses of the system at the time it was approved and the prudence of the system for regulated activities alone.

Given the significant level of SAP-related expenditures, they should be amortized over a much longer period of time than suggested by the company. A minimum of five years should be used, beginning in the year when SAP is shown to have been fully placed into service and to have become fully used and useful for purposes of PacifiCorp's regulated activities.

B. *Glenrock Mine*

The proposed Glenrock Mine adjustment is an out-of-period adjustment. The mine was not closed until October 1999. Fuel savings resulting from the closure will not occur until 1999 and beyond. Mine closure costs should be amortized over a period of at least 5 years, beginning with a test period no earlier than 1999. Such an amortization will more properly match costs and benefits. This adjustment is more than just a re-calculation of the remaining life of the mine. Rather, it was based upon a decision to close the mine before the end of its useful life because of the availability of lower-cost fuel. Under those circumstances, it is fundamentally unfair to saddle current ratepayers, who are not yet enjoying any significant benefits from the decision, to begin paying the costs of the same.

C. *Condit Dam*

The Company's proposal to accelerate depreciation of the Condit Dam is flatly inconsistent with its recent depreciation stipulation. Even absent the stipulation, however, beginning the amortization in 1998 would not be appropriate because the agreement relating to removal costs was not signed until 1999, is not yet approved, and is subject to change.

III. *COST OF SERVICE*

The LCG continues to have concerns and issues over a number of allocation issues utilized in the cost of service studies filed in this case, and it reserves the right to assert its positions on those issues in the future. For purposes of this case, however, the LCG supports the cost of service study submitted by PacifiCorp with its direct testimony. That cost of service study produces reasonable and equitable results for purposes of this case.

The concerns expressed by Committee witness Yankel about the company's cost of service results do not raise any serious issues or concerns about the validity of the cost of service study. The basis for measuring system peaks is a policy issue with many impacts, but it does not call into question the accuracy or validity of the 1998 cost of service results. His concerns over load research data also do not raise any serious questions about the accuracy or validity of the 1998 cost of service results. Indeed, Mr. Yankel cannot offer any specific recommendations to improve the data.

Division witness Townsend proposes to weather normalize monthly peak demands for certain rate schedules, using preliminary numbers developed by the Company. Company employees and others have acknowledged that weather normalization of peak demands is very difficult and imprecise. [E.g., Tr., p.987, l.24 - p.988, l.11 (Taylor)]. Although the LCG does not necessarily disagree with the concept, assuming valid analysis and data, the preliminary company data utilized by Mr. Townsend has not been sufficiently analyzed or verified to be reliable.

Mr. Townsend also proposes to use a plant allocation factor instead of a labor factor for Accounts 926 (Employee Pension & Benefits) and 929 (Duplicate Charges). Mr. Townsend states that he is not trying to create an issue in connection with these adjustments because they nearly offset each other and because they have minimal impacts on cost of service results in 1998. Given the lack of impact, it may not be critical for the Commission to resolve the issue in this proceeding. Nevertheless, as acknowledged by Mr. Townsend, these expenses appear more related to labor. The LCG believes that these expenses are clearly more related to labor than to plant and that they should continue to be allocated on the basis of a labor allocation factor.

Several witnesses have commented on the fact that four winter evening peaks occurred during calendar year 1998. Those comments do not provide any logical basis for questioning the validity of the test year cost of service studies or results. Rather, they call into question whether those results are representative of future years. Given the Commission's use of historical test years, it is not appropriate to ignore actual test year data because of the uncertainty of future years' data.

The LCG submits that the cost of service study submitted by the Company is fair and reasonable and produces just and reasonable results for purposes of this case, and should be adopted by the Commission.

IV. *RATE SPREAD*

The Company's 1998 cost of service study should be used as the primary basis for determining rate spread. High load factor customers have endured significant increases in cost responsibility in recent years. For example, in the last rate case the Company proposed a departure from the historical Utah practice of allocating production costs on the basis of 8 coincident peaks and 100% demand. The LCG argued that the Company's proposal was not consistent with cost-causation principles and that a departure from historic allocation practices was not justified. The Commission approved the Company's use of 12 coincident peaks and a 75/25 demand/energy split, resulting in a significant shift in responsibility for production and transmission costs to high load factor customers. In addition, the refund ordered in the 1997 case was spread on an even percentage basis to all major customer classes, thus, failing to mitigate the disparity in contributions among various classes. Finally, adjustments made in the Company's cost of service study between its direct and rebuttal testimony channeled nearly all of the savings from a $12 million reduction in the company's revenue requirement proposal to schedules other that Schedule 9. [Tr., p.990, ll. 9-12 (Taylor)].

While the LCG is not challenging the Commission's prior rulings in this case, it should be recognized that a significant shift in cost responsibility to high load factor customers has already occurred. Further shifting of cost responsibility to large customers based on proposed changes to allocation procedures or on rate spread proposals that deviate from cost of service results would tend to unfairly increase the burden on Utah businesses. Customer classes should be moved towards cost of service, other than as necessary to avoid undue rate shock.

The LCG recognizes and supports the principles of rate stability and gradualism. The Division's multi-year analysis of peak load data was done in this context. A consideration of cost shifts occasioned by shifting load patterns is certainly appropriate. Examination of those principles, however, should not be confused with questioning the validity of test year cost of service results. If principles of gradualism or rate stability are needed--for example, if the Commission orders a rate increase of the magnitude requested by PacifiCorp--the Division's mitigation techniques would be appropriate. If, however, the Commission orders a revenue requirement decrease or a modest increase, rate spread should be based primarily upon test year cost of service data.

Division Witness Wilson correctly noted that adjustments are appropriate for customer classes that are ten percent or more outside the target rate of return. Committee Witness Yankel's argument that a system-average adjustment should be made to all rate schedules should be rejected. The use of across-the-board rate decreases in the last case, however reasonable, resulted in further exacerbation of unequal class contributions. There is no justification for ignoring the 1998 class cost of service results in this case and further compounding the disparate contributions required of the various customer classes.

Company witness Griffith's proposal to cap rate increases at 1.5 times the overall average may have some merit at higher revenue requirement levels. His proposal is not appropriate, however, at more limited revenue requirement levels. As with the three-year analysis or three-year averaging utilized by the Division and the Company, a 1.5 limitation is appropriate only as an impact mitigation measure. At moderate increases, it is not appropriate to utilize such a technique. Indeed, the use of such a limitation could result in certain classes moving even further from cost of service--an inappropriate result, even by Mr. Griffith's standards. [Tr., p.1258, ll.5-10 (Griffith)].

V. *RATE DESIGN*

If a rate increase is ordered for Schedule 9 customers, the entire increase should be placed on the demand component of the customer bill. The current energy charge incurred by Schedule 9 customers is far in excess of the energy cost reflected by the cost of service studies. This results in unfair and discriminatory treatment within the rate schedule for those customers with higher than average load-factor profiles. In order to address this inequity, any rate increase resulting from this proceeding to Schedule 9 rates should be assigned solely to the demand component. Conversely, any rate decrease to Schedule 9 should be targeted solely to the energy component.

VI. *SYSTEM BENEFITS CHARGE*

The LCG recognizes the value of various public benefit programs. However, utility regulation and regulated utility rates are typically not the appropriate means for implementing or funding social programs. For the most part, public policy and social programs should be adopted and directed by legislative action. The LCG would not oppose a process designed to identify current public benefit program expenses inherent in the current rate structure, or to identify objectives, operations and impacts of a "stand alone" type of public benefit program. If the Commission is interested in considering stand-alone public benefit programs in the future, it should encourage the OEPR or another appropriate state agency to initiate a process involving all stakeholders designed to investigate all relevant issues, options and impacts.

VII. SPECIAL CONTRACT TASK FORCE REPORT

The LCG participated actively in the Special Contract Task Force and has no substantial disagreements with the report produced by the task force. However, no compelling reasons were discovered by the task force for any significant change in the way special contracts have historically been considered and approved by the Commission. The task force essentially reached the same conclusions as the 1992 task force report. Either the 1992 criteria or the criteria suggested in the new task force report are workable, so long as they are applied in a flexible manner and are adaptable to each specific context.

By their very nature, special contracts involve customers and situations that are atypical. Moreover, the industry is in a tremendous state of flux. Rigid application of any set of criteria would be counterproductive and imprudent. The task force report reflects general concepts and principles that are, for the most part, unobjectionable. They should not, however, be burdened with inflexible interpretations or applications. The Commission, utility, state agencies and actual and potential utility customers must have sufficient flexibility to respond to unique or changing circumstances as they present themselves. For example, the task force report proposes a 5-year maximum term for special contracts with no "automatic" renewals. An inflexible restriction is both unnecessary and unwarranted. While the guideline may be reasonable as a general principle, it must be subject to adaptation and change in the face of new or changing circumstances.

Similarly, the task force report proposes that contracts should generally make a minimum 5% contribution to fixed costs. The report acknowledges some circumstances in which this requirement should not be imposed, and other such circumstances clearly exist. Such a guidelines should be utilized in a flexible manner. Moreover, it is far from clear how a 5% requirement would be measured or determined in any event.

The report also utilizes terms such as "fixed and variable costs" and "incremental capacity and energy costs" without providing clear definitions or measurement tools. Arriving at specific definitions or rules for application of such concepts would prove contentious and difficult. The measurement methods mentioned briefly in the report—such as IRP, avoided costs and average variable costs—may not adequately address changing markets or conditions and may prove not to be the best means of measurement over time. All affected parties must remain free to present arguments and information in support of a "public interest" finding by the Commission, without artificial restrictions imposed by inflexible criteria.

Finally, criteria used to evaluate a new special contract may need to be applied in a different manner in the context of a contract renewal. It would hardly be in the economic best interests of the State of Utah to attempt to lure industries into the state with a special contract, and then try to impose a different type of pricing structure when a contract is up for renewal. Any such “bait and switch” tactics would be inequitable, imprudent and shortsighted.

The LCG submits that the special contract task force report, considered in its proper context and utilized in a reasonable and flexible manner, can provide guidance to the Commission and all affected parties. The LCG does not believe, however, that it necessary or appropriate to “adopt” the criteria or report. Rather, the Commission should commend the task force participants for providing useful information and guidelines that can be considered by the Commission as appropriate.

CONCLUSION

PacifiCorp's net power cost methodology is overly complex, resistant to audit, and terribly out of date. PacifiCorp has continued to use a computer program that no longer runs on modern computers, written in an obsolete computer language no longer supported by its vendors, based on data adjusted by two other computer programs, and coded to include industry structures no longer in existence. In addition, the computer program suffers from numerous operating problems and erroneous calculations. In effect, Pacific has chosen to forecast the past and failed. They have given the lie to the maxim that hindsight is better than foresight. The Commission should largely reject PacifiCorp’s net power cost calculations. For purposes of this case, the Commission should utilize PacifiCorp’s actual 1998 short-term sales and revenues as an offset to power costs, correct PacifiCorp’s unreasonable assumption that the quantity of power available in the market will not affect prices, and normalize the effects of significant one-time losses experienced in the summary of 1998. PacifiCorp's net power costs, system-wide, should be set at $306 million, rather than $430.2 as argued by PacifiCorp. Looking forward, the Commission should instruct PacifiCorp that it will no longer accept net power costs calculations based on the obsolete, error-riddled PD/Mac model, and should direct PacifiCorp, in consultation and cooperation with the Division, Committee and other interested parties, to develop a reasonable and verifiable means of calculating net power costs.

PacifiCorp employed a set of arbitrary, unsupported and complicated adjustments, each designed to reduce average wholesale revenues. None of these complicated steps is necessary or appropriate, given that actual data is readily available. There is no valid reason not to use actual data for both quantities and prices of 1998 wholesale sales. Sales-for-resale revenues should be returned to actual 1998 levels, with a resulting decrease to net power costs of $23.34 million for Utah. Mr. Falkenberg and Ms. Wilson's proposal to use actual market prices for short term firm sales and purchases is a good first step, but it fails to also make the correction for actual short term sales quantities. PD/Mac calculations should also recognize the indisputable link between quantity and prices, with a corresponding $9.33 million reduction net power costs in Utah. Finally, PacifiCorp's short term sales during the summer of 1998 should be returned to profitability rather than assume the repeat of management misjudgments in 1998, thus reducing net power costs by $3.61 million for Utah.

PacifiCorp's PD/Mac program should be "normalized" to eliminate numerous inherent biases designed to overstate power costs. Much of the logic is out of date. Many of the market structures are no longer in use; some of them are no longer even legal. Data is undocumented and confusing. It is nothing short of remarkable that these critical and substantive net power cost calculations are done, by deliberate choice, on obsolete, inefficient and unreliable tools rather that readily-available, economical and superior alternatives. The Commission should reject PD/Mac as a power cost model on a going-forward basis.

On this record, SAP expenses have not been shown to have been prudent for purposes of PacifiCorp's regulated activities only. A thorough audit should be ordered for all SAP-related expenditures before cost recovery is allowed. In any event, no significant portion of SAP-related expenses should be included in a 1998 historic test year because it was not used and useful on a company-wide basis until at least 1999. SAP costs must be properly allocated between PacifiCorp's regulated and unregulated activities. Finally, SAP-related expenditures should be amortized over a period of at least five years.

The proposed Glenrock Mine adjustment should be rejected as an out-of-period adjustment. The proposed Condit Dam adjustment should also be rejected as inconsistent with the recent depreciation stipulation and order, and because it is an out of period adjustment.

The Company's cost of service study should be adopted for purposes of this case, and should be the primary basis for spreading rates. If utilization of principles of gradualism and rate stability are appropriate, as they would be with a rate increase of the magnitude requested by PacifiCorp, the Division’s proposed rate mitigation technique should be utilized. At a revenue requirement decrease or increase of the magnitude recommended by the Division, rate spread should be based primarily upon the test year cost of service results.

If a rate increase is ordered for Schedule 9 customers, it should be targeted solely to the demand component of the bill to reduce the unfair and discriminatory intra-class results of inordinately high energy costs.

If the Commission is interested in considering stand-alone public benefit programs in the future, it should encourage the OEPR or another appropriate state agency to initiate a process involving all stakeholders designed to investigate all relevant issues, options and impacts.

No compelling reasons exist for any significant change to the handling of special contracts or for the "adoption" or the task force report. Any guidelines or criteria must be applied in a flexible manner that is adaptable to each specific context.

Dated this 28th day of April, 2000.

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CERTIFICATE OF SERVICE

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