Office of the Secretary
Service Date
June 7, 2002

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA UTAH POWER & LIGHT COMPANY FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES.	)	**CASE NO. PAC-E-02-1**
	)	**ORDER NO. 29034**

On January 7, 2002, PacifiCorp dba Utah Power & Light Company (PacifiCorp; Company) filed an Application with the Idaho Public Utilities Commission (Commission) requesting approval of proposed electric service schedules. The Company's Application has four parts: 1) a proposed Schedule 34 – Bonneville Power Administration (BPA) Exchange Credit distribution; 2) a proposed electric service schedule adjusting rates to bring customer classes closer to cost-of-service (COS); 3) a proposed Power Cost Surcharge ($38 million including carrying charges); and 4) a proposed Rate Mitigation Adjustment (RMA) designed so that no customer classes would have an increase during the two-year period of the surcharge.

The Commission ordered that the BPA exchange credit be implemented on February 1, 2002, while the remaining issues were considered. On April 11, 2002, a Stipulation and Settlement was filed by PacifiCorp, Monsanto Company, the Idaho Irrigation Pumpers Association and the Commission Staff regarding all other issues. The proposed settlement: 1) limits recovery of excess power costs to $25 million; 2) accelerates the remaining two years of the PacifiCorp/ScottishPower merger credit and reduces the excess power costs by $2.3 million; 3) establishes a Power Cost Surcharge designed to recover excess power supply costs of $22.7 million over a two-year period; 4) restructures the irrigation tariff schedules to provide firm power; and 5) adjusts revenue responsibility to bring the irrigators closer to cost of service.

We recognize at the outset the size of both the BPA credit for qualifying residential and small farm customers and the amount of excess power supply costs the Company has asked to recover are extraordinarily large. We find that the magnitude of each, however, derives from a common set of circumstances, i.e., prolonged drought, natural gas price increases, the regional demand for electricity, power supply shortages and California market flaws. All of these factors contributed to the extraordinarily high wholesale market prices of power realized in the Northwest during 2000-2001 which in turn contributed to the BPA exchange settlement.

In this Order, the Commission reaffirms its previous authorization of the BPA Exchange Credit distribution. After reviewing the record, we also approve as fair, just and reasonable the proposed Stipulation and Settlement with one modification. The Commission determines that Nu-West is a contract customer and not subject to the Power Cost Surcharge. We further award the Idaho Irrigation Pumpers Association and Tim Shurtz intervenor funding. Finally, we direct PacifiCorp to provide each customer with a one time credit of $20.00 for failure to provide the individual customer notice required by Rule 102 of the Commission's Customer Information Rules. IDAPA 31.21.02.102.

I. THE BPA CREDIT

The Company's Application was processed in two parts. The first dealt with the BPA credit and was processed using Modified Procedure, i.e., pursuant to written submission rather than hearing. IDAPA 31.01.01.201-204. The second part dealt with the Company's request to recover through a Power Cost Surcharge $38 million in excess net power supply costs accrued during the period November 2000 through October 2001 and to implement other proposed changes.

The BPA credit was approved in Interlocutory Order No. 28946 and became effective February 1, 2002. The BPA credit is a distribution of exchange benefits negotiated by Northwest utilities and state regulatory Commissions in a May 2001 Settlement Agreement with the BPA. As contemplated by the 1980 Pacific Northwest Electric Power Planning and Conservation Act, the credit passes the benefits of the Federal Columbia River Power System to PacifiCorp's qualifying residential and small farm customers in eastern Idaho.

The dollar amount of the 2001 BPA credit is by any measure extraordinary and far exceeds historical levels. Facing the same volatile and high-priced market as everyone else in the Northwest, BPA chose to offer an additional financial settlement rather than go to the market to buy ever more expensive power to serve its commitments. PacifiCorp's quick action in accepting the financial settlement resulted in an additional $11.5 million, or a 50% increase in benefits for its Idaho customers. No other Idaho electric utility was able to secure this additional level of benefit for its customers because the market prices for power fell and BPA withdrew the settlement offers. This settlement came about as a result of the very same market conditions that were responsible for PacifiCorp's unprecedented level of purchased power expenses. The chaotic market conditions underlie both the large size of the current BPA credit and the huge energy costs accumulated in the deferred accounts.

The 2001 BPA financial settlement provides $34 million in benefits to qualifying customers for the first year, and $35.2 million in the second year. To account for four months of accrued credit (October 1, 2001 through February 1, 2002), the rate for residential customers the first year was set to distribute 16 months of a normal year's benefit, or $40.6 million. The first year BPA credit for small farm customers was based on a 12-month distribution because the irrigation season is largely completed by October 1 each year.

Exchange benefits for PacifiCorp are historically allocated 43% to residential customers and 57% to small farm customers. That was the allocation proposed and accepted in the interlocutory Order. The BPA credit implemented in February reduced residential customers base rates by an average of 44% and reduced small farm irrigation base rates by 63%.

Commission Findings: The Commission reaffirms its Order No. 28946 approving the distribution of the BPA credit. The BPA credit will continue to be reflected as a separate line item on a customer's bill. The BPA credit in its full amount remains intact and is unaffected by our Order today.

The Commission would be remiss, however, if it failed to note that the size of the present BPA credit may create in customers an artificial or false sense of security. This exchange benefit is temporary and customers would be wise to explore options to reduce their future load requirements with conservation and demand side management (DSM) measures. In doing so they will be prepared when the BPA credit no longer includes the additional financial benefit resulting from the volatile wholesale market.

We now turn to the remainder of the Company's filing including the cost-of-service (COS) study, proposed Power Cost Surcharge and rate mitigation adjustment (RMA).

II. PROCEDURAL HISTORY

On February 5, 2002, the Commission issued a Notice setting a prehearing conference on February 19, 2002. It also notified the public and other parties that the Commission Staff intended to pursue a settlement of the remaining issues presented in this case and set the first settlement conference to follow the prehearing conference. Commission Rules of Procedure 271-280, IDAPA 31.01.01.271-280.

A. Parties

The following parties of record participated in settlement negotiations and hearing:

PacifiCorp	James F. Fell, Esq. Stoel Rives LLP
Monsanto Company	Randall C. Budge, Esq. Racine, Olson, Nye, Budge & Bailey
Idaho Irrigation Pumpers Association	Eric L. Olsen, Esq. Racine, Olson, Nye, Budge & Bailey
Tim Shurtz	Pro Se
Commission Staff	Scott Woodbury, Esq.

The following additional party was granted late intervenor status and participated only at hearing:

Nu-West Industries	Conley Ward, Esq. Givens Pursley LLP

B. Identification of Issues

Following the prehearing and settlement conferences, the Commission on February 26 issued a Notice identifying the following matters as continuing to be "at issue" in this case. The issues to be addressed in this case were:

- Company cost-of-service study w/related adjustments to rate design.
- The revenue ramifications of the Company's filing.
- Power costs PacifiCorp is seeking to recover.
- Rate mitigation adjustment.
- Whether the Company's attempted recovery of excess power costs incurred in 2000/2002 violates Merger Approval Condition No. 2. Reference Case No. PAC-E-99-1, Order No. 28213, page 31 issued November 15, 1999, i.e., "following the merger, PacifiCorp shall not seek a general rate increase effective prior to January 1, 2002"; see also Order No. 28213, page 31, fn. 22 "our Order imposes the additional condition of a rate moratorium for approximately two years. PacifiCorp is entitled to seek a rate increase to be effective in year three if it can prove that its revenue requirement is deficient."

- Whether it was appropriate (and perhaps prudent) for PacifiCorp to enact economic curtailments of usage (Company imposed interruptions of power) as opposed to the alternative purchase of high cost power.

- The presence of interruptible load, and the Company's treatment of same.

- A review of Company sales contracts executed in 2000/2001.

- The timing of the loss of the Company's Hunter coal generation plant in 2000-2001 and related cause(s) therefore.

- The treatment of irrigators (i.e., previously interruptible, now proposed to be firm).

- The treatment of special contract customers (previously system customers, now proposed to be situs).

On February 26, 2002, the Commission issued another Notice that established alternate hearing schedules; a May hearing date should the parties be successful in reaching a settlement; and a July hearing date if the parties were unsuccessful in reaching a settlement agreement, if the settlement agreement failed to resolve all issues, or if the settlement agreement was not accepted by the Commission.

C. The Stipulation and Proposed Settlement

On April 11, 2002, a Stipulation and Proposed Settlement was filed by PacifiCorp, the Staff, the Idaho Irrigation Pumpers Association (IIPA) and Monsanto Company (collectively referred to as the "Settlement Parties"). Exh. 20; See Stipulation and schedules attached to this Order. Although he participated in and attended the settlement conferences, Intervenor Tim Shurtz did not sign the Stipulation. The submitted Stipulation, in part, contains the following language:

> ¶ 4. Pursuant to the Commission's identification of issues and Notice of Settlement Conference in this matter, the parties have engaged in discussions with a view toward resolving PacifiCorp's Application in this case.
>
> ¶ 5. PacifiCorp has claimed and sought recovery of approximately $38 million in excess net power costs, including carrying charges, incurred during the period November 1, 2000 through October 31, 2001 (the "excess power costs"). The Commission Staff proposed recovery be limited to approximately $21 million after adjustments for the Hunter 1 outage, wholesale contract costs, load growth, and jurisdictional allocation. Both IIPA and Monsanto asserted that: (1) recovery of excess power supply costs is barred by reason of

the ScottishPower-PacifiCorp Merger Approval Condition No. 2 (footnote omitted); (2) power supply costs associated with the Hunter Plant failure are not recoverable because they were incurred subsequent to the deferral Order; (3) any Hunter-related costs properly deferred should be equitably shared as a result of maintenance issues; (4) costs associated with certain wholesale contracts were imprudently incurred and not recoverable; (5) thorough review and approval of the Company's cost-of-service studies was required before rates could be shifted among the customer classes. IIPA also challenged the Company's BPA credit allocation, the proposed RMA, and the elimination of irrigation A-B-C rate schedules. The Company disagreed and presented further information in response to the positions advanced by the Parties. The Company asserted that all of its Excess Power Costs were prudently incurred and are properly recoverable.

Based upon the settlement discussions among the parties, as a compromise of the disputes in this case, and for other consideration as set forth below, the parties agreed to the following terms:

TERMS OF THE STIPULATION

¶ 6. PacifiCorp shall be allowed to recover, through a surcharge and the acceleration of the "Merger Credit," as described below, $25 million for Excess Power Costs.

¶ 7. As a result of the Commission's Order ("Merger Order") in the ScottishPower merger case (Case No. PAC-E-99-01), customers have received since January 2000 a credit of approximately $1.6 million per year from PacifiCorp that has been reflected as a line item on customers' bills pursuant to Electric Service Schedule No. 99 (the "Merger Credit"). If PacifiCorp were to continue such credit for the full four-year period reflected in the Merger Order, there would be approximately $2.3 million, on a present value basis, remaining to be credited to customers. The parties agree that in order to offset PacifiCorp's Excess Power Costs, the merger credit and Electric Service Schedule No. 99 shall be accelerated and credited to reduce the Excess Power Cost recovery from $25 million to $22.7 million.

¶ 8. PacifiCorp shall be allowed to implement a power cost surcharge (the "PCS") designed to recover $22.7 million over a 24-month period beginning May 15, 2002 and ending May 14, 2004.... A true-up...may be implemented over a 12-month period immediately following the 24-month PCS recovery period to reflect any under- or over-collection of the total authorized PCS amount.

...

Stipulation pp. 2-4.

As reflected in the filed testimony of parties supporting the Stipulation, the proposed settlement incorporated implementation of the Schedule 34 BPA credit, recovery of extraordinary power supply costs with a rate mitigation adjustment, a modified revenue requirement across customer classes and changes in the Schedule 10 irrigation class rate design. Tr. pp. 305, 307. The proposed settlement also incorporated a modified irrigation class revenue requirement that brings the irrigators closer to their cost of service. The effect of this change permits a reduction in rate increases to other customer classes that would otherwise occur due to power supply cost recovery. Tr. pp. 305, 316. The impact of the power supply cost recovery is reduced by applying what is termed a rate or revenue mitigation adjustment (RMA) to various customer classes and spreading recovery over two years with a third year true-up. The resultant proposed changes in rates over those in effect in 2001 are a 34% decrease for Schedule 6A general service customers; a 28.2% decrease for residential customers; a 28% decrease for irrigation customers; and a maximum 4% increase for Schedules 6, 9, 10 and 13 commercial and industrial customers. See Stipulation Attachment B, Table BB2.

D. Public Hearing

To further the Commission's review of the Application and proposed settlement the Commission directed that parties prefile testimony in support or opposition to the Application and Settlement. To promote public participation in this case, the Commission also scheduled an evidentiary technical hearing, public workshops, public hearings, and provided an opportunity for written comment. Pursuant to Notice, public hearings were held in Rigby and Preston on May 6 and 7, 2002 to take customer testimony in this case. The hearings were preceded by public workshops where the Company and Staff made independent presentations and answered questions. The evidentiary hearing was also held on May 7 to hear testimony from the parties, both supporting and opposing the settlement. In addition to the parties of record, many former and sitting Idaho Legislators attended the hearings.

The Commission has reviewed and considered the record in this case including: the proposed Stipulation and Settlement Agreement, the transcript of proceedings and exhibits, and the filed comments of customers and parties. We acknowledge that most customers providing testimony opposed the settlement for a number of reasons. We have carefully considered their testimony in our decision and address those concerns in greater detail below.

1. <u>The Settlement Process</u>. The proposed settlement was criticized as being the result of a process that failed to provide an early opportunity for public participation. Some customers contend that the public was not consulted and that their opinions were not sought out. It is important to note, the Commission finds, that the record does not support such criticism. This Commission sought public input from the very beginning of this case with its initial Notice of Application and solicitation of comments and invitation to intervene. (January 16, 2002.) The Notice was served on every city and chamber of commerce in PacifiCorp's service area. An additional opportunity presented itself with Commission Notices of Prehearing and Settlement Conferences. The Stipulation was filed with the Commission on April 11 and hearings and workshops were scheduled for eastern Idaho in early May. With each Order and Notice the Commission issued a press release. The Commission, however, cannot control how local media outlets choose to treat our press releases.

Under Commission procedural rules, settlement negotiations of parties by their very nature are confidential. IDAPA 31.01.01.271-280. As is the case with the Court Rules, confidentiality promotes the open and frank discussion of issues and is intended to promote a just and speedy resolution to disputes. Although the discussions are confidential, participation is open to the Company, all intervenors and the Staff. It is not a process that is intended to be an open public forum. The post-hearing comments filed by Monsanto and the Idaho Irrigation Pumpers Association give some insight into the settlement process in this case. Relevant excerpts from those comments are as follows:

Monsanto

> Monsanto is mindful of the fact that this Commission has allowed Idaho Power and Avista to recover excess power supply costs incurred under similar circumstances.
>
> While the cost of service studies and methodologies presented by PacifiCorp were not adopted or accepted by Staff or intervenors, a Rate Mitigation Adjustment (RMA) was used to accomplish cost shifts among the customer classes in a manner perceived to be a fair and equitable shift in the general direction of cost-of-service. [It was] the parties' reasonable belief and anticipation that the Commission likely would make a similar cost shift had the case been concluded through contested hearing. By <u>the Stipulation, the parties achieved a known and certain result, eliminated risks, and avoided the time and expense of a contested hearing</u>. As <u>in any compromise, the opportunity of achieving a better result was foregone, while the risks of a worse result avoided</u>.

Monsanto Post-Hearing Comments p. 3 (emphasis added).

Irrigators

> The Irrigators have actively participated in the settlement negotiations that have led up to the presentation of the Stipulation.
>
> The agreed upon net recovery of approximately $22.7 million in excess power costs is reasonable and appropriate given the risks of a less favorable result, the Irrigators' limited resources, and in light of other settlements reached in other jurisdictions on this issue.
>
> Although PacifiCorp's cost of service studies and methodologies were not accepted by Staff, the Irrigators or Monsanto, the <u>Irrigators agreed to the RMA</u> [Rate Mitigation Adjustment] <u>in light of (1) the historical perception that the class as a whole was under cost of service and (2) the practical realization that the Commission would make such a shift if the matter was resolved through a contested hearing</u>. The Irrigators want to stress the ability to make such an adjustment was only made possible in the aggregate by the extraordinary BPA exchange credit available to this class.

Irrigator Comments pp. 1-3 (emphasis added).

The Commission is convinced that in appropriate cases negotiated settlement when found reasonable is a preferred outcome. It is certainly often a better use of party and Commission resources. In this case there appeared to be credible arguments on both sides of the issues and inconclusive results in other jurisdictions. All this led to the uncertainty and perceived risks of going to hearing recognized by Monsanto and the Irrigators. Thus the opportunity existed for reciprocal concessions and a reasonable resolution of the issues without contracted litigation.

The Commission Rules contain procedural safeguards for proposed settlements. As reflected in Commission Rule 275, proponents of a proposed settlement carry the burden of showing that the settlement is reasonable, in the public interest, or otherwise in accordance with law or regulatory policy. IDAPA 31.01.01.275. Pursuant to Rule 276, the Commission is not bound by settlements. This Commission reserved making judgment as to the reasonableness of the Settlement until after the public hearings concluded and the record was closed.

2. <u>The Company's Private Representations</u>. The comment heard most often from customers at the public hearings was that the Company's attempt to recover November 2000 – October 2001 power costs breaks a promise made during the time of the ScottishPower/

PacifiCorp merger. More specifically, many commentors recalled that PacifiCorp promised not to raise rates for a period of three to five years. As one customer stated "a promise is a promise – a contract is a contract – its called integrity and when a person or a company breaks or tries to break a promise or a contract, you can no longer trust that person or company." Tr. p. 453. Although this promise was reportedly made by PacifiCorp's CEO in "behind the scenes" private discussions with eastern Idaho Legislators (Tr. p. 58) and in newspaper advertisements by the utility, (Tr. pp. 44,45), it was not part of the Company's merger filing before the Commission. Thus, it was not part of the testimony or record that the Commission was permitted to consider. Nor were these promises disclosed to the Commission following issuance of the Merger Order – it was not raised by any party or person in a request for reconsideration or clarification. *Idaho Code* § 61-626 (Reconsideration); IDAPA 31.01.01.325 (Clarification). Because no one placed this fact in the record, we are constrained to base our findings on the record before us. *Idaho Code* § 61-629; *Mountain View Rural Tele. Co. v. Interstate Utilities Co.*, 55 Idaho 86, 38 P.2d 40 (1934). While this Commission can appreciate the anger of the Company's customers, we are bound by our previous Orders and the evidence of record that those decisions rested upon.

It appears the private meeting at a cabin between elected officials and utility representatives led to a public misinterpretation of Merger Condition No. 2. Tr. pp. 435-37. From this meeting those elected officials in attendance appear unanimous in their conclusion that utility officials made significant promises regarding future treatment of expenses. The Commission has no reason to discount those perceptions. However, because these promises from the cabin meeting were never made known to the Commission and placed in the merger case record, they were not considered then and we are legally unable to consider them now. It is important to distinguish that while it is entirely appropriate for elected officials to meet with utility representatives to discuss the status of an ongoing case before the Commission, the opposite is true for Commissioners. The Commission as a quasi-judicial body must confine its decision to the record produced at hearing. Failing to do so we violate procedural due process of law. Amendment 14, U.S. Constitution; *Idaho Historic Preservation Council v. Boise City Council*, 134 Idaho 651, 8 P.3d 646 (2000). Had a Commissioner been in attendance at such a meeting, without providing sufficient notice to all the parties in the case, that Commissioner's action could constitute a dereliction of duty and be grounds for dismissal. With that said, under the circumstances surrounding the meeting at the cabin and the promises reportedly made, this Commission could not legally use that information to formulate its decision either then or now.

What seems to have compounded the confusion over the interpretation of Merger Condition No. 2 is that when the Commission issued its Order in the merger case, this condition appears to have mirrored some of the perceived promises made at the cabin meeting. Apparently, the existence of Merger Condition No. 2 led some to conclude that the Company's promises to elected officials had been incorporated fully into the Commission's Order. But this, as was mentioned previously, is not the case. For the Commission to have done so would have incorporated into our Order an inappropriate ex parte or off the record communication. What the Commission intended with Condition No. 2 was clearly articulated in the merger Order. That condition, coupled with the merger credit, was intended solely to result in a rate reduction that would last through January 1, 2002. The word "freeze" was never used in that Order and there was no mention of expenses during the moratorium being disallowed for future recovery. In fact, that condition clearly anticipated that rates could go up after January 1, 2002. Furthermore, the only way for a rate increase to have been effective on January 1, 2002 is if non-merger expenses that were incurred during the moratorium period were included. It is indeed unfortunate for everyone involved that the events of the meeting at the cabin have contributed to this misinterpretation of Condition No. 2.

3. Merger Condition No. 2. This Commission addressed Merger Condition No. 2 pursuant to a Petition for Clarification in this case filed by the Intervenor Tim Shurtz. Order No. 28998 issued April 12, 2002. This issue was raised repeatedly in public comments, so we will address it again. Merger Approval Condition No. 2 stated:

> At a minimum, ScottishPower shall not seek a general rate increase for its Idaho service territory effective prior to January 1, 2002.

Case No. PAC-E-99-1, Order No. 28213 p. 8. The Commission findings explained at page 31:

> As a final and irrefutable measure to ensure that rates will not increase as a result of the merger, we hereby impose the additional condition (Merger Approval Condition No. 2) that following the merger, PacifiCorp shall not seek a general rate increase effective prior to January 1, 2002. This literally guarantees that PacifiCorp's customers will see an immediate rate reduction lasting at least two years through the combination of the merger rate credit and the moratorium on general rate increases imposed herein.

In our prior Order No. 28998, we provided the following clarification:

> On November 15, 1999, after nearly a year of investigation and numerous hearings, the Commission issued Order No. 28213 approving the merger of PacifiCorp with Scottish Power. Many issues and concerns were raised in the course of that proceeding, notably service quality and rates. Approval of the merger was subject to 46 conditions to address the concerns raised and ensure that the public interest was served by approval of the merger. <u>Merger Condition No. 2 set forth above was included to prevent the Company from increasing customer rates for any reason prior to January 1, 2002</u>. Thus customers were guaranteed a two-year period of rate stability, and Commission oversight to prevent any merger related increases was enhanced.
>
> On November 1, 2000, PacifiCorp filed an Application for a deferred accounting order. Extraordinarily high wholesale market prices outside the control of the Company were resulting in actual costs for the Idaho jurisdiction that greatly exceeded Idaho's allocated share. Intervenors in that case argued that the application should be dismissed because its approval would violate conditions imposed by the merger Order. <u>The Commission found that authorization of deferred accounting for these expenses was only a mechanism to preserve them for future consideration, not a guarantee of future recovery and would not result in a rate increase prior to January 1, 2002</u>. Approval of PacifiCorp's request for a deferred accounting order, we found, was not a violation of the merger condition that no rate increase should be requested to be effective prior to that date. Our decision simply provided PacifiCorp the opportunity to request and litigate the recovery of such costs in the future.
>
> On January 2, 2002, PacifiCorp filed this case. One of the matters now at issue is the recovery of the costs that were deferred pursuant to our earlier Order. Intervenor Shurtz has requested that we clarify why consideration of the deferred amounts is not a violation of the Merger Conditions prohibiting rate increases before January 1, 2002. The answer is clear from an examination of the language of the condition imposed. <u>PacifiCorp was prohibited from seeking a general rate increase effective prior to January 1, 2002. It did not seek any increase in rates to be effective before 2002, therefore the Company has fulfilled that condition</u>. The Commission specifically found in Order No. 28630 that <u>deferred accounting was appropriate for the unanticipated and extraordinarily high power costs experienced as a result of the wholesale market</u>. That deferral preserved those expenses for consideration now. We do not decide whether, or how much, if any, of those expenses should be passed on to customers. We do find that there is not and can not be a violation of Merger Condition No. 2 if those costs are approved for recovery, either as part of a settlement or otherwise.

Order No. 28998 pp. 2-3 (emphasis added).

The power cost expenses the Company seeks to recover in this case are not merger related expenses. Nor, as was suggested by some customers and Intervenor Tim Shurtz, are they the result of any "learning curve" or a result of a foreign company learning the ropes in the Northwest energy market. It was not a lack of experience that caused PacifiCorp to incur these power cost expenses. Similar expenses were incurred by nearly every utility in the western interconnection, both public and private, including Idaho Power Company and Avista Utilities. Tr. p. 329. The price spike in the wholesale market in late 2000 through mid-2001 was unprecedented and was clearly not foreseen or anticipated by anyone at the time of the ScottishPower/PacifiCorp merger.

The Commission did not intend by imposing Merger Condition No. 2 that PacifiCorp and its shareholders be required to solely bear the costs associated with a subsequent and unforeseen series of events that triggered a run-up of extraordinary costs. We ensured a period of rate stability for eastern Idaho customers, many of whom were opposed to the merger that we approved. We provided the Company's customers with a tangible benefit of rate stability for two years—a benefit they have received and a benefit the Farm Bureau recognized was of value. Tr. pp. 379, 405, 406. Moreover, the requested power costs were <u>extra</u>ordinary, simply meaning that they were unforeseen and out of the ordinary. Indeed, the drought conditions and the unprecedented market prices for wholesale power were well out of the ordinary.

Mr. Shurtz, in response to Commission questioning, stated that although he believes the Company under Merger Condition 2 could file a rate case on January 1, 2002, it could not use a test year or expenses from the moratorium period. Tr. pp. 375, 376. Mr. Shurtz's interpretation is incorrect from both a regulatory and an equity or fairness standpoint. *Agricultural Products Corp. v. Utah Power & Light*, 98 Idaho 23, 26, 557 P.2d 617, 619 (1976). It would be unfair to the Company and would deny customers the benefit of using the most recent test year information for determining the Company's load/resources profile and establishing authorized expenses. As explained in our Orders, the Commission finds that the Company would have been permitted to file a rate case in 2001 as long as rates did not change or become effective prior to January 1, 2002. Tr. p. 379.

It was also suggested by Intervenor Tim Shurtz and by other customers that before any monies are paid to PacifiCorp, the Company should be required to file a general rate case. General rate cases can result in rate increases as well as decreases (Tr. p. 447), and also in a realignment of customer class revenue responsibility. As a matter of regulatory oversight, we note that the Staff performs an audit of PacifiCorp's accounts and operations every three years. The nature and extent of the audit is as if the Company had filed for a general rate case. The purpose of Staff's audit is to determine if the Company is over-earning and to assess whether its rates continue to be just and reasonable.

PacifiCorp provides a utility service to the public pursuant to a Certificate of Public Convenience and Necessity that obligates the Company to provide service regardless of cost and to charge only rates approved by this Commission. *Idaho Code* §§ 61-307 and 61-313. This is a constraint that does not apply to unregulated businesses. In this case, the Commission authorized a deferral accounting mechanism for extraordinary power costs incurred by PacifiCorp between November 2000 through October 2001 to acquire adequate resources to meet its service obligation. As a regulatory body this Commission has a dual obligation, one to the utility to ensure that the utility is allowed such rates as will produce sufficient funds to meet necessary maintenance and operating expenses, and to provide it with an opportunity to earn a fair and reasonable return on the value of its property devoted to the public service. On the other hand, the Commission has an obligation to customers to ensure that the service they receive is adequate, safe and reliable and that rates they pay are fair, just and reasonable. *Idaho Code* §§ 61-301; 61-302; *Grindstone Butte Mutual Canal Co. v. Idaho PUC*, 102 Idaho 175, 627 P.2d 804 (1981).

4. Hunter Plant Failure. Several commentors argued that the Company be prohibited from recovering the power costs due to the Hunter plant outage. As reflected in testimony, the reason for failure of the Company's Hunter Unit No. 1 Generation facility on November 24, 2000 has not been determined with any certainty, neither in this case nor in any jurisdiction in which the issue has been litigated. Tr. pp. 241, 242. The Company states it knows answers to the questions what, where and when; but not why. The evidence, it states, is gone. The Company contends that operating practices and maintenance was not a contributing factor. Tr. pp. 243, 244. The generation unit, it notes, was recently overhauled in 1999. Tr. p. 246. A customer states "the Company built it, the Company operated it, the Company maintained it – It wasn't an act of God. It was a mechanical failure. They have to take responsibility for that." Tr. p. 442.

That the failure of Hunter caused the Company to go to market for replacement power is undisputed. The question is: Should there be a sharing of responsibility in costs? The proposed settlement does not attempt to assign blame or allocate a specific percentage of sharing for Hunter.

The settlement provides a negotiated recovery figure and not a road map to determine how the figure was determined. Any attempt by this Commission to allocate to Hunter a portion of the difference between the Company Application for $38 million to the settlement amount of $25 million is, we find, a meaningless exercise. We note only that Staff in its initial negotiating position recommended a 25% discount ($2.97 million) of the approximate $11.9 million Hunter costs included in the $38.3 million of the power supply costs the Company is seeking to recover. Staff Exh. 102. It is important to note that the Hunter costs in the Company's filing include only the net costs above and beyond what would have occurred had Hunter operated normally, i.e., the replacement energy costs. No capital costs associated with repair of the Hunter plant that were subject to insurance or the deductible are included in the $38.3 million the Company requested. Tr. pp. 250, 251.

In summary this Commission hopes that our discussion of the above issues provides the Company's customers with a better understanding of what this Commission can consider in making its decisions and the nature of the obligations we must fulfill both to the utility and to its customers. We also hope that we have provided customers with some insight as to the difference between a private and regulated company. PacifiCorp is obligated to provide its customers with power. That obligation is a service requirement. The Company cannot just choose to turn off the switch. But neither is it provided carte blanche as to how it operates and what it charges. This Commission provides regulatory oversight. We require the Company to prove its case and in making our decision we consider all evidence in the record.

We next turn to the remaining issues.

E. Power Supply Costs

In Order No. 28630 (Case No. PAC-E-00-5) the Commission unanimously authorized PacifiCorp to defer excess net power costs resulting from increases in the electric market price commencing November 1, 2000 through October 31, 2001. In our Order we stated:

> Although the Commission approval of PacifiCorp's Application for a deferred accounting order will allow the Company the opportunity to seek recovery of these costs, it does not guarantee future recovery of any deferred amounts. The Company must ask for recovery in a separate, future proceeding where the Commission will review the prudency of any deferred amounts to determine whether the Company is entitled to recover them from its customers.

Order No. 28630 p. 6. The Company now seeks recovery of deferred power costs in this case.

The total amount of extraordinary power supply costs incurred by the Company and attributable to the Idaho jurisdiction is $49 million. However, $11 million of those costs were incurred prior to November 1, 2000 and are therefore outside the authorized period of deferral. As a result, the Company's shareholders bear the full responsibility for those costs and they will not be passed on to customers. The Stipulation and Proposed Settlement includes recovery of $25 million (65%) of the $38 million in power supply costs and carrying charges requested by PacifiCorp. Tr. pp. 260; 257, 258. When viewing the Company's total power purchases, the Settlement represents a 50/50 sharing between customers and the utility.

In assessing the power supply costs in this filing, Staff stated that it evaluated the normalized power supply costs allocated to the Idaho jurisdiction, the deferral period accrual amounts, the impact of wholesale power sales contracts, and the ramifications of the Hunter plant failure. Tr. p. 307. As reflected in filed testimony, the generation resources available to PacifiCorp during the authorized accrual period was affected by the second worst water year on record (Tr. p. 219), and the loss of the Company's Hunter generating plant on November 24, 2000. The decrease in system generation forced the Company to look off-system (i.e., the western wholesale market) for replacement power. The replacement resources available to PacifiCorp to serve its load obligations, the Company states, were power purchases from the market at extraordinarily high prices.

Intervenor Shurtz urged the Commission to deny recovery of these costs in large part, attributing them to mismanagement and inexperience. He stated that ratepayers should not be penalized for the Company's "growing pains." Tr. p. 360.

Commission Findings: Based on our review of the testimony filed in this case by PacifiCorp and Commission Staff and the supporting comments of Monsanto and the Irrigators, the Commission finds with relative certainty that the proposed power supply cost settlement amount of $25 million is fair, just and reasonable. While not specifically broken out into cost components, this amount is nevertheless comprised of Idaho's jurisdictional share of excess net power costs incurred by PacifiCorp during the authorized deferral period. Although the public has expressed a need to know how the $25 million was calculated, we recognize and accept that the amount is a result of a negotiated settlement. From the Company's perspective there was no specific delineation of costs. Tr. p. 296. Considered by the parties were the Company's short-term power purchases, wholesale power contracts, strategies in serving load, load growth, and individual assessments to the probability of a party prevailing on a challenge of imprudence. Tr. pp. 298-300. Because we believe the settlement amount to be reasonable and in the public interest, we accept the $25 million settlement figure and forego the uncertainty that would otherwise accompany a full evidentiary hearing on the issues. The parties in their negotiating process have arrived at a number that they all feel is reasonable, but each one may have a different basis in looking at the costs for why they feel that it is reasonable. We feel with certainty that many of the disallowances identified by Staff (Hunter 1 outage, wholesale contract costs, load growth and jurisdictional allocation) are included in the final Settlement figure.

F. Acceleration of Merger Credit and Power Cost Surcharge

The proposed settlement reduces the impact of the power supply cost by accelerating the remaining two years of the Schedule 99 merger credit – a calculated present value of $2.3 million. Tr. pp. 265, 314. The resulting power cost surcharge is thus designed to recover not $25 million, but $22.7 million over a 24-month period beginning May 15, 2002 and ending May 14, 2004. The power cost surcharge will be implemented as a line item charge on a customer's billing through electric service Schedule 93, with a potential third-year true-up. Tr. p. 265. Under Schedule 93, a cents per kilowatt hour surcharge will be assessed on a customer's monthly metered usage as determined by the Voltage Level at which a customer takes service.

Commission Findings: The Commission finds the proposed Schedule 93 surcharge and method of collection to be reasonable. The Commission further agrees with the Settlement Parties that the use of the Schedule 99 merger credit to reduce the amount of power cost surcharge to customers is not an elimination or loss of the credit but is instead an acceleration of the credit. We find this to be of substantial benefit and value to customers and approve of the propose change in merger benefit delivery and related accounting. Additionally, this accelerated treatment helps insure the likelihood that customers who were taking service at the time of the merger actually benefit from the credit. With acceleration of the credit, the present line item for the Schedule 99 merger credit on a customer's billing will be eliminated.

G. Customer Class Revenue Requirement and Rate Mitigation Adjustment (RMA)

Commission Staff states that its objective in settlement negotiations and allocating the revenue requirement to customer classes was to create a package that appropriately applied the

BPA credit, equitably distributed power supply cost recovery responsibility, and ultimately, moved the irrigation class closer to perceived cost of service. Tr. p. 315.

The Settlement Parties propose that the Rate Mitigation Adjustment (RMA) in the Stipulation will be reflected as a line item charge on customers' bills through electric service Schedule 94. Tr. pp. 263, 264. In year one, the RMA applies only to commercial, industrial and lighting customers. In year two, the RMA continues and will apply to all customer classes. No customer class will receive a price increase in year two. Irrigation customers in year two will see an average additional rate decrease of 11%. In year three and subsequent years, the RMA may continue subject to termination provisions contained in the Stipulation. The Settlement Parties have agreed that upon the earlier of: (1) the expiration of the current electric service Schedule 34 BPA Exchange Credit; or (2) the adoption by the Commission of a cost-of-service study for PacifiCorp and the subsequent implementation for all customers of the approved cost of service study by any lawful method, the electric service Schedule 94 RMA will be terminated. Tr. p. 269.

Intervenor Shurtz argued that it was inappropriate to consider the RMA in the absence of a general rate case. Tr. p. 360. He stated that the RMA was "an arbitrary and unequal way of mitigation costs to all classes of consumers." *Id.*

Commission Findings: The distribution of power cost recovery and realignment of the irrigation class cost-of-service without a significant increase to any class, we find, was only made possible by what the stipulating parties recognized to be an extraordinarily large BPA credit to small farms. Given the facts of this case, the Commission finds the proposed allocation method for Company recovery of deferred excess power costs to be fair, just and reasonable. We also find reasonable the proposed Schedule 94 Rate Mitigation Adjustment (Exh. 20; Stipulation Attachment D) and commend the Irrigators for their willingness to participate in a voluntary realignment of cost of service and related assumption of revenue responsibility. Rather than an arbitrary distribution, we find this realignment is of benefit to all other customer classes. In Order No. 23508 issued January 18, 1991, the Commission noted that the irrigation class provided one of the lowest returns of all the customer classes. It is appropriate to reduce that disparity in this case.

H. Rate Design—Irrigation Class

As reflected in the proposed Stipulation, the rate structure for all customer classes except the irrigation class remains unchanged. The rate design proposal for the irrigation class is an elimination of the separate A, B and C firm and interruptible schedules in favor of a single, revenue-neutral, firm service rate. Exh. 20; Stipulation Attachment C. The proposed service charges and demand charge are calculated as the average of the three current rate options, proportioned for the amount of usage under each of the three rate options. The Settlement Parties also proposed to modify the energy rate component from a two-block, declining rate to a three-block, declining rate. The three-block energy charge is designed to more closely track cost of service while giving more uniform price signals to all irrigation customers. Tr. pp. 271, 272.

Recognizing that some irrigators use energy at levels not eligible for the BPA credit (e.g., Schedule 10 – Irrigation Season Rate C), larger irrigation customers on a case-by-case basis may still be able to obtain individual interruptible or load-control contracts for the 2002 irrigation season. PacifiCorp agreed to interruptible contracts with not more than 15 large irrigators (defined as irrigators having an individual meter registering more than 500 kilowatts during the last 12 months) on a first come – first serve basis. Tr. pp. 272, 273. PacifiCorp has agreed to work with irrigators to develop an optional load control program beginning with the 2003 irrigation season, and has committed to file such a program with the Commission no later than January 31, 2003.

Commission Findings: The Commission finds the proposed Stipulation changes for the Electric Service Schedule 10 – Irrigation and Soil Drainage Pumping Power Service tariff (Exh. 20; Stipulation Attachment C) to be fair, just and reasonable. We specifically note that the Irrigators strongly supported this proposal. We encourage the Company to work with irrigators in the manner proposed and expect it to follow through on its commitments.

I. Nu-West Modification

At hearing, the Commission granted Nu-West Industries' Petition to Intervene out of time. Under the proposed settlement and stipulation, Nu-West would be treated as a tariff customer and allocated a share of the power costs the Company seeks to recover. The power cost surcharge allocated to Nu-West is $936,000. After giving effect to a rate mitigation adjustment to Nu-West of $777,000, the net effect is a $159,000 per year rate increase for Nu-West in each of the next two years.

Nu-West argued that under its 1998 Service Agreement (July 1, 1998 – December 31, 2001' Exh. 501), its rates were fixed during the term of the Agreement, and neither PacifiCorp nor the Commission was authorized to alter these rates except upon an extraordinary showing that the rate is "so low as to adversely affect the public interest – as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden or be unduly discriminatory." *Citing Agricultural Products Corporation v. Utah Power & Light*, 98 Idaho 23, 29, 557 P.2d 617 (1976). No such showing, as to the unreasonableness of the then existing contract rates or that the then existing contract was unreasonable vis-à-vis the public interest, Nu-West stated, has been made or even attempted in this case.

Nu-West also insisted that it relied on the Company's original proposal in this case – no increase to any customer class. Tr. p. 345. The Commission's Notice, however, apprised Nu-West that "the rates and charges of all customers, including those governed by special contract, are at issue and subject to change." It was during settlement negotiations, Nu-West states, that it became vulnerable to an increase. Tr. p. 345. Nu-West did not participate in the settlement conferences.

Commission Findings: The Commission finds that Nu-West had legal notice of proceedings in this case and technically could have participated. We nevertheless find merit in its assertion and the nature of the contract service received under its 1998 Service Agreement with PacifiCorp. Consequently, we find that it would be inappropriate to include Nu-West in the proposed power cost surcharge.

PacifiCorp at hearing (Tr. p. 348) and in post-hearing filed Exhibit 25 (Option 3 tables BB1-BB3) recommended that in the event that Nu-West is excluded from the power cost surcharge, the amount allocated to Nu-West be collected from tariff customers during the 12-month true-up period. PacifiCorp clarified that it will not recover any carrying charges or earnings on the Nu-West amount deferred for collection during the true-up period. The Commission finds the Company proposed Exhibit 25 Option 3 to be acceptable and reasonable. The Option 3 tables BB1-BB3 illustrating the impact of our decision have been inserted into the Stipulation attached to this Order.

III. INTERVENOR FUNDING

The Commission received timely applications for intervenor funding in this case from both the Idaho Irrigation Pumpers Association and from Mr. Shurtz. IDAPA 31.01.01.161-170. Tim Shurtz requests an award of $10,173; the Irrigators seek an award of $32,378. Both applications satisfy the procedural requirements of Commission Rule 162.

1. Tim Shurtz requests intervenor funding in the following amount:

Tim Shurtz 152 hours at $40 per hour	$ 6,080.00
Travel meals and miscellaneous expense	$ 693.00
Legal (Alva Harris) 20 hours at $125/hour	$ 2,500.00
Assistant (Gilbert Dayley) 15 hours at $40/hour	$ 600.00
Clerical Assistant 12 hours at $25/hour	$ 300.00
TOTAL	$10,173.00

Mr. Shurtz noted that his position differed from Staff and other parties in that he contended the Company's requested recovery of excess power costs was prohibited by Condition 2 of the Merger Agreement. He also contended the Hunter outage was the responsibility of the Company. Finally, he argued that piecemeal ratemaking was wrong and that the Company recovery should be required to file a general rate case before authorizing. Mr. Shurtz felt that without his participation as an intervenor, the public would have remained largely uninformed and would not have participated in this case.

PacifiCorp opposes Mr. Shurtz's application for intervenor funding, contending that such an award cannot be made if the Commission approves the Stipulation because the law requires that an intervenor make a material contribution to the Commission's decision.

2. The Irrigators request intervenor funding in the following amount:

Legal 117.9 hours at $135 - $150/hour	$16,107.00
Travel, meals, lodging, etc.	$ 1,071.68
Consulting fees (Tony Yankel) 152 hours at $100/hour	$15,200.00
TOTAL	$32,378.00

The Irrigators stated that by their participation they sought to limit the Company's recovery of its claimed excess power supply costs to only those that were prudently incurred and properly recoverable. Of utmost importance to the Irrigators were the rate spread and rate design aspects of this case. By way of the Stipulation, the Irrigators agreed to: (1) the revision of the ABC tariff schedule to that of a firm rate; and (2) to use of a modified rate mitigation adjustment (RMA) feature that has the effect of making a substantial move for the irrigation class toward cost of service and redistributing the revenues to the benefit of the other customer classes to principally mitigate the effect of the Company's excess power supply costs.

Commission Findings: The Commission's decision whether to award intervenor funding and in what amount is controlled by *Idaho Code* § 61-617A and Rule 165 of the Commission's Rules of Procedure. IDAPA 31.01.01.165. We find that both intervenors contributed materially to our decision in this case. While we did not ultimately agree with the recommendations of Mr. Shurtz in this case, that is not a prerequisite to an award of intervenor funding. We appreciate Mr. Shurtz's efforts to be involved in our process. It is the policy of this Commission to offer a reasonable opportunity for a variety of interests to present their positions before the Commission. Mr. Shurtz's Petition for Clarification helped to define the applicability of Merger Condition No. 2. We further find the Irrigators participation and involvement in the settlement process to be critical to the fashioning of what we find to be a reasonable and equitable solution to this Company's recovery of excess power costs and the recognition of class cost of service.

Pursuant to Rule 165 the total award for all intervening parties combined shall not exceed $25,000 in any proceeding. Based on our review of the intervenors' relative contributions to our decisions in this case, we find it reasonable to award the Irrigators $22,500 and Tim Shurtz $2,500. The intervenor funding award shall be recovered from all customer classes. This amount may be deferred until the next general rate proceeding or in another appropriate case.

IV. FAILURE TO PROVIDE NOTICE TO CUSTOMERS

An issue raised in the public hearings was the adequacy and sufficiency of the public notice, specifically what attempts were made to notify customers of the Company's Application. Some customers indicated they learned of the Commission's hearings only serendipitously and did not get informed until it was too late to study, prepare and testify. Nu-West also raised the issue of adequate notice.

The Commission finds notice to customers of impending changes in rates and charges to be a serious matter. While this Commission provides public notice of utility applications, procedure, scheduling and hearings, and provides press releases regarding same to the media, we have no control over actual media coverage.

Idaho Code § 61-307 establishes a requirement that schedules with the proposed changes in rates and services be filed with the Commission and kept open for public inspection. The Company reports that its filing was made available for public inspection at the Company's offices in Rexburg, Preston, Shelley, and Lava Hot Springs, Idaho. The Company claims it has met the statutory notice requirement. In reviewing the official record in this case, we agree. However, this does not complete our inquiry.

Rule 102 of the Commission's Utility Customer Information Rules requires a utility to provide each customer with individual notice (through bill stuffers or an additional comment page with the customer's bill) of a utility's application for a general or tracker rate change. IDAPA 31.21.02.102. Our Rule requires that the customer notice shall make it clear that the application is a proposal, subject to public review and a Commission decision. It shall also inform customers that a copy of the utility's application is available for public review at the offices of the both the Commission and the utility. *Id.* The Commission finds that the Company's Application in this case is of such nature that Rule 102 notice was required. The Commission is informed in this case by a letter received by Commission Staff on May 15, 2002 that the Company acknowledges that it failed to comply with the Rule 102 customer notice requirement.

Rule 102 also requires that the utility issue a press release containing the same information presented in the customer notices to all newspapers, radio and television stations listed on the Commission's news organization list for the utility. The press release is to be mailed or delivered to media outlets simultaneously with filing of the Application and a copy of the press release is to be filed with the application. Although the press release in this case was not filed with the Application, the Commission is informed that on May 15, 2002 Commission Staff was provided with a copy of the Company's January 7, 2002 press release.

While failure to comply with the Rule 102 notice requirements creates no due process or other procedural rights in customers (IDAPA 31.21.02.102.05), we find it is a serious violation of a Commission rule. Failure to provide the required individual notice potentially limits public participation in our proceeding. See *Idaho Code* § 61-617A(1). This violation triggers Commission powers to affect an appropriate remedy under the provisions of Title 61, Chapter 7.

Idaho Code § 61-706 establishes a maximum penalty for each offense of $2,000 per day. In this case the Commission finds that the lack of individual notice by the Company to each of the Company's 54,386 customers constitutes a violation of Rule 102. Based on these facts, the Commission could theoretically seek a civil penalty of $108,772,000. For failure to provide notice, the Commission finds it reasonable to require the Company to provide each customer a credit of $20.00 or a total of $1,087,720. This credit shall be provided to customers within 90 days of the date of this Order. The Company may prorate the credit over this 90-day period to avoid cash flow concerns. *Idaho Code* §§ 61-703; 61-501.

In crafting this credit regarding notice failure, the Commission intends to send a strong signal to the Company that it needs to be more responsible in its communication with customers. Not only must it comply with regulatory requirements, but it should strive to ensure that a consistent message is conveyed in its filings with this Commission, in its media and marketing efforts, and in its efforts to influence public officials.

V. CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Utah Power & Light Company, an electric utility, and the issues presented in Case No. PAC-E-02-1 pursuant to Idaho Code, Title 61, the Commission's Rules of Procedure (IDAPA 31.01.01.000 *et seq.*) and the Commission's Utility Customer Information Rules (IDAPA 31.21.02).

ORDER

In consideration of the foregoing and as more particularly described above and detailed in the attached Stipulation and schedules that accompany this Order, IT IS HEREBY ORDERED that the Stipulation and proposed settlement submitted by PacifiCorp, Commission Staff, the Idaho Irrigation Pumpers Association and Monsanto Company, with the exception of the power cost surcharge allocated to Nu-West Industries, be and hereby is approved, and that in accordance therewith

- PacifiCorp is allowed to recover, through a surcharge and the acceleration of the Electric Service Schedule No. 99 "Merger Credit," $25 million for excess power costs.

- PacifiCorp is allowed to implement a power cost surcharge (PCS) designed to recover $22.7 million over a 24-month period to begin the day following the service date of this Order. The PCS is to be implemented as a line item charge on a customer's bill through Electric Service Schedule No. 93.

- The Schedule 93 PCS is to be separately tracked and accounted for and a true-up surcharge may be implemented over a 12-month period immediately following the 24-month PCS recovery period to reflect any under- or over-collection of the total authorized PCS amount.

- The power cost surcharge allocated by the Stipulation to Nu-West Industries is to be collected from tariff customers during the 12-month, Schedule 93 PCS true-up period (reference Exhibit 24—Option 3 Tables BB1-BB3).

- The revenue obligations of the various customer classes (except for Nu-West Industries, described above) is to be spread among the classes in the manner described in Stipulation Attachment B.

- Electric Service Schedule No. 10 for Irrigators is amended as set forth in Stipulation Attachment C.

- The Rate Mitigation Adjustment (RMA; Stipulation Attachment D) is approved as described and set forth in the Stipulation and is to be reflected as a line item charge on customers bills through electric Service Schedule 94.

IT IS FURTHER ORDERED that Tim Shurtz is awarded intervenor funding in the amount of $2,500. The Idaho Irrigation Pumpers Association, Inc. is awarded intervenor funding in the amount of $22,500. PacifiCorp is directed to pay these amounts within twenty-eight (28) days pursuant to Rule 165.02 of the Commission's Rules of Procedure, IDAPA 31.01.01.

IT IS FURTHER ORDERED that PacifiCorp for failure to provide the individual notice required by Rule 102 of the Commission's Customer Information Rules (IDAPA 31.21.02.102) is hereby directed to provide each customer a credit of $20.00 within 90 days of the service date of this Order. If the Company fails to make this credit, then the Commission shall request that the Attorney General institute an action to recover $1,087,720 as a civil penalty as authorized by law.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case No. PAC-E-02-1 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this Case No. PAC-E-02-1. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 7th day of June 2002.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

See separate concurring and dissenting opinion of Commissioner Hansen.

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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CONCURRING AND DISSENTING OPINION
OF COMMISSIONER DENNIS S. HANSEN
ORDER NO. 29034
CASE NO. PAC-E-02-1

I respectively concur in Parts I and III, partially concur in Part IV and dissent as to Part II of the Order.

Consistent with my dissent in Order No. 28998, I disagreed with the decision allowing PacifiCorp to recover extra costs it may have incurred during the rate moratorium. I still strongly agree with the prior dissenting opinion. However, based on the Commission's ruling in Order No. 28630, we allowed the Company to petition the Commission for deferred costs during the moratorium period.

Here again, I must dissent from the Order approving the $25 million settlement. I understand that the deferred amount the Company seeks during the moratorium occurred at a time of high prices in the electricity market. I also realize losing the Hunter unit cost PacifiCorp a considerable amount of money to replace that power. However, I believe PacifiCorp has other costs that are declining that would help to offset some of the deferral amount, which was contemplated in the merger stipulation. Merger savings were supposed to reduce costs.

After reviewing our Rules of Procedure for consideration of a negotiated settlement (Rule 274, 275 and 276), I believe it is the Commissioners who retain the responsibility of making the final judgment of whether the proposed settlement is "fair, just and is in the public interest."

Rule 275 makes clear that proponents of a proposed settlement, "carry the burden of showing that the settlement is reasonable." Rule 276 notes that the Commission is not bound by settlements and "will independently review" any settlement proposed. IDAPA 31.01.01.275-276.

This is where I feel the problem lies in this case. It is my opinion that this settlement hides issues that perhaps ought to be aired before the settlement is declared to be in the public interest.

In my opinion, neither PacifiCorp nor other parties adequately justify the details of the $25 million in deferred costs agreed to in the settlement, when they presented their settlement proposal to the Commission. Therefore, detailed evidence was lacking which would allow me to make a reasoned decision that it was "reasonable and in the public interest." PacifiCorp made no explanation of how the 65 percent of deferred cost was configured. The Commission was told only that the $25 million settlement was 65 percent of the total $38 million deferral.

The failure of the Hunter plant which provides much of Idaho's power was really not addressed. I find it very unusual that in 18 months the Company has not been able to determine the cause of the failure, yet in testimony they maintain that PacifiCorp's operating or maintenance practices or procedures did not contribute to or in any way cause the failure. Also, I find it interesting in its comments that Staff concluded "PacifiCorp had some responsibility in the failure and should share responsibility for a portion of extraordinary costs." Without more detail, I cannot judge how that responsibility is being shared.

The question not answered is: How much, if any, of the Hunter failure is included in the $25 million settlement? No one seems to know the answer, including the Commission. Evidence was also presented in a letter to the Commission from Jim Smith of Monsanto Company. The letter indicated that PacifiCorp could have done more to reduce the high-cost of power purchases by interrupting power to Monsanto Company, its largest customer. That could have made a considerable amount of power available at below the prevailing market price at that time.

Other questions not answered in the settlement agreement nor in the hearings are: How much of the $25 million is related to hydro conditions in Idaho? How much is related to increased wholesale power business? How much to honoring wholesale contracts? How much concerns load growth in the Idaho service area? How much is related to poor Company business decisions? I need to see some evidence on these issues to make a justifiable decision.

Another area of concern is that the public, in my opinion, was not given proper notice of these proposed settlement negotiations. As addressed in Part IV of the Order most of the public had little time to properly prepare and study the effect it may have on them. In my judgment this violation warranted a larger credit. I cannot, in all honesty, determine that this settlement is in the public interest, when so very little information was provided to the Commission regarding what constitutes the settlement.

As it now stands, this Order simply accepts what PacifiCorp, Commission Staff, Monsanto Company (whose rates are unaffected by this case), and irrigation customers have agreed to in this settlement. I believe this settlement amount was taken out of the hands of the Commission and I cannot accept this proposal on blind faith.

In conclusion, the Commission lacks sufficient evidence about the many important issues that were specifically called for in the Order approving the deferred accounting treatment. If provided, this evidence would enable me to make a decision whether the request to allow the Company to recover such extraordinary costs is just, reasonable, fair and in the public interest. The customers who are now being asked to pay this recovery cost thought that in the merger they would be protected from just such an event. Without pertinent details, I cannot assure these customers that this recovery is fair, just, and reasonable or in the public interest. Consequently, I must respectfully dissent.

Dennis S Hansen

DENNIS S. HANSEN, COMMISSIONER

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of PACIFICORP dba Utah Power & Light Company for Approval of Changes to Its Electric Service Schedules	))))	CASE NO. PAC-E-02-1 STIPULATION

This stipulation ("Stipulation") is entered into by and among PacifiCorp, doing business as Utah Power & Light Company ("PacifiCorp" or the "Company"), the Idaho Public Utilities Commission Staff ("Staff"), the Idaho Irrigation Pumpers Association ("IIPA") and Monsanto Company ("Monsanto") (collectively referred to as the "Parties").

I. INTRODUCTION

1. The terms and conditions of this Stipulation are set forth herein. The Parties agree that this Stipulation represents a fair, just and reasonable compromise of the issues raised in this proceeding and that this Stipulation is in the public interest. The Parties, therefore, recommend that the Public Utilities Commission ("Commission") approve the Stipulation and all of its terms and conditions. Reference IDAPA 31.01.01.272, 274.

II. BACKGROUND

2. On November 1, 2000, PacifiCorp filed an Application in Case No. PAC-E-00-5 for approval to defer excess net power costs incurred from November 1, 2000 through October 31, 2001. In Commission Order No. 28630, the Commission approved the Company's request for deferred accounting of excess net power costs. Pursuant to deferral authority, the Company deferred approximately $37 million in excess net power costs attributable to Idaho. On November 24, 2000, PacifiCorp experienced an outage at its Hunter 1 generating unit. The Hunter 1 unit became fully operational on May 8, 2001. The outage of the Hunter 1 unit increased the Company's net power costs.

3. On January 7, 2002, PacifiCorp filed the Application in this case seeking to recover the deferred excess net power costs, with carrying charges, amounting to approximately $38 million over a two-year period. The Company further proposed electric service schedules that would adjust rates to bring customer classes closer to the cost of serving the respective classes and to implement an increase to the Electric Service Schedule No. 34 BPA exchange credit to reflect the increased benefit from a settlement with the Bonneville Power Administration regarding residential exchange benefits. Further, the Company proposed a Rate Mitigation Adjustment ("RMA") designed to result in no customer classes receiving an increase during the two-year period of the surcharge for the recovery of the deferred excess net power costs.

4. Pursuant to the Commission's Identification of Issues and Notice of Settlement Conference in this matter, the Parties have engaged in discussions with a view toward resolving PacifiCorp's Application in this case.

5. PacifiCorp has claimed and sought recovery of approximately $38 million in excess net power costs, including carrying charges, incurred during the period November 1, 2000 through October 31, 2001 (the "Excess Power Costs"). The Commission Staff proposed recovery be limited to approximately $21 million after adjustments for the Hunter 1 outage, wholesale contract costs, load growth, and jurisdictional allocation. Both IIPA and Monsanto

asserted that: 1) recovery of excess power supply costs is barred by reason of the ScottishPower - PacifiCorp Merger Approval Condition No. 2[1]; 2) power supply costs associated with the Hunter plant failure are not recoverable because they were incurred subsequent to the deferral Order; 3) any Hunter related costs properly deferred should be equitably shared as a result of maintenance issues; 4) costs associated with certain wholesale contracts were imprudently incurred and not recoverable; 5) thorough review and approval of the Company's cost-of-service studies was required before rates could be shifted among the customer classes. IIPA also challenged the Company's BPA credit allocation, the proposed RMA, and the elimination of irrigation A - B - C rate schedules. The Company disagreed and presented further information in response to the positions advanced by the Parties. The Company asserted that all of its Excess Power Costs were prudently incurred and are properly recoverable.

Based upon the settlement discussions among the Parties, as a compromise of the disputes in this case, and for other consideration as set forth below, the Parties agree to the following terms:

III. TERMS OF THE STIPULATION

6. PacifiCorp shall be allowed to recover, through a surcharge and the acceleration of the "Merger Credit," as described below, $ 25 million for Excess Power Costs.

7. As a result of the Commission's order ("Merger Order") in the ScottishPower merger case (Case No. PAC-E-99-1), customers have received since January 2000 a credit of approximately $1.6 million per year from PacifiCorp that has been reflected as a line item on customers' bills pursuant to Electric Service Schedule No. 99 (the "Merger Credit"). If

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[1] Merger Approval Condition No. 2 provides: "At a minimum, ScottishPower shall not seek a general rate increase for its Idaho service territory effective prior to January 1, 2002." Case No. PAC-E-99-1, Order No. 28213, p. 8. With respect to that Condition, in its findings the Commission stated: "As a final and irrefutable measure to ensure that rates will not increase as a result of the merger, we hereby impose the additional condition (Merger Approval Condition No. 2) that following the merger, PacifiCorp shall not seek a general rate increase effective prior to January 1, 2002. This literally guarantees that PacifiCorp's customers will see an immediate rate reduction lasting at least two years through the combination of the merger rate credit and the moratorium on general rate increases imposed herein." Case No. PAC-E-9901, Order No. 28213, p. 31.

PacifiCorp were to continue such credit for the full four-year period reflected in the Merger Order, there would be approximately $2.3 million, on a present value basis, remaining to be credited to customers.[2] The Parties agree that in order to offset PacifiCorp's Excess Power Costs, the merger credit and Electric Service Schedule No. 99 shall be accelerated and credited to reduce the Excess Power Cost recovery from $25 million to $22.7 million.

8. PacifiCorp shall be allowed to implement a power cost surcharge (the "PCS") designed to recover $22.7 million over a 24-month period beginning May 15, 2002 and ending May 14, 2004. The PCS will be implemented as a line item charge on customers' bills through Electric Service Schedule No. 93, attached hereto as Attachment A. As reflected in Attachment A, the Parties have agreed that the PCS recovery should be tracked and that a true-up surcharge may be implemented over a 12-month period immediately following the 24-month PCS recovery period to reflect any under- or over-collection of the total authorized PCS amount.

9. The Parties agree that the revenue obligations of the various customer classes shall be spread among the classes in the manner described in Attachment B. The Parties further agree that Electric Service Schedule No. 10 shall be redesigned in accordance with Attachment C. In response to concerns from the IIPA concerning the loss of the Schedule 10, Irrigation Season Rate C and its associated load control benefits, PacifiCorp agrees that it is willing to discuss individual interruptibility or load control contracts for the 2002 irrigation season with not more than 15 large irrigators[3] on a first come – first served basis upon individual request of a member of said class of irrigators for such discussion. PacifiCorp also agrees that it will work with the IIPA and the irrigators as a class to develop an optional load control program for the 2003 irrigation season and thereafter that would allow an irrigator to participate in such program

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[2] Under the terms of the Merger Order, PacifiCorp can avoid the $1.6 million dollar credit during the last two years, i.e., 2002 through 2003, to the extent that cost reductions related to the merger are reflected in rates.

[3] For purposes of paragraph 9 of this Stipulation, "large irrigators" are defined as irrigators having an individual meter registering greater than 500 kW demand during the last 12 months.

on an annual basis. PacifiCorp shall file its proposed optional load control program with the Commission no later than January 31, 2003.

The Parties also agree that the RMA will be implemented as a line item charge on customers' bills through Electric Service Schedule No. 94, attached hereto as Attachment D. The Parties further agree that upon the earlier of (1) the expiration of the current Electric Service Schedule No. 34 BPA exchange credit or (2) the adoption by the Commission of a cost of service study for PacifiCorp and the subsequent implementation for all customers of said approved cost of service study by any lawful method by the Commission or PacifiCorp, Electric Service Schedule No. 94 will be terminated.

10. The Parties agree that this Stipulation represents a compromise of the positions of the Parties in this case. Other than the above referenced positions and any testimony filed in support of the approval of this Stipulation, and except to the extent necessary for a Party to explain before the Commission its own statements and positions with respect to the Stipulation, all negotiations relating to this Stipulation shall be treated as confidential.

11. The Parties submit this Stipulation to the Commission and recommend approval in its entirety pursuant to IDAPA 31.01.01.274. Parties shall support this Stipulation before the Commission, and no Party shall appeal any portion of this Stipulation or Order approving the same. If this Stipulation is challenged by any person not a party to the Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

12. In the event the Commission rejects any part or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding, within 15 days of the date of such action by the Commission, to withdraw from this Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to seek reconsideration of the Commission's order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate.

13. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

14. No Party shall be bound, benefited or prejudiced by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery, and no Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future. Without limiting the generality of the foregoing, nothing in this Stipulation, and nothing asserted in the negotiation of this Stipulation, shall be the basis of waiver or estoppel in Case No. PAC-E-01-16 (Monsanto). No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

15. The obligations of the Parties under this Stipulation are subject to the Commission's approval of this Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal by a court of competent jurisdiction.

Respectfully submitted this 10th day of April, 2002.

PacifiCorp

By ~~Erinn Kelley-Siel~~ 4-9-02
~~Erinn~~ Kelley-Siel, its ~~attorney~~ of record

Idaho Public Utilities Commission Staff

By______________________________
Scott D. Woodbury, its attorney of record

Idaho Irrigation Pumpers Association

By______________________________
Eric L. Olsen, its attorney of record

Monsanto Company

By______________________________
Randall C. Budge, its attorney of record

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Respectfully submitted this 10th day of April, 2002.

PacifiCorp

By______________________________
Erinn Kelley-Siel, its attorney of record

Idaho Public Utilities Commission Staff

By Scott D. Woodbury
Scott D. Woodbury, its attorney of record 4/09/02

Idaho Irrigation Pumpers Association

By______________________________
Eric L. Olsen, its attorney of record

Monsanto Company

By______________________________
Randall C. Budge, its attorney of record

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Respectfully submitted this 10th day of April, 2002.

PacifiCorp

By______________________________
Erinn Kelley-Siel, its attorney of record

Idaho Public Utilities Commission Staff

By______________________________
Scott D. Woodbury, its attorney of record

Idaho Irrigation Pumpers Association

By 4/8/02
Eric L. Olsen, its attorney of record

Monsanto Company

By 4-8-02
Randall C. Budge, its attorney of record

CERTIFICATE OF SERVICE

I hereby certify that on this 10th day of April, 2002, a true and correct copy of the foregoing was served on the following via U.S. mail:

Scott Woodbury
Deputy Attorney General
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Peggy Ryan

utah power & LIGHT COMPANY

UTAH POWER & LIGHT COMPANY

ELECTRIC SERVICE SCHEDULE NO. 93

STATE OF IDAHO

POWER COST SURCHARGE

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers (including Schedule 400 – Nu-West Industries Inc.) taking service under the terms contained in this Tariff.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt-hour as determined by the Voltage Level at which the Customer takes service. The charges in the column labeled "Year 1" shall be in effect for one year beginning on the effective date of this tariff. The charges in the column labeled "Year 2" shall be in effect for one year beginning at the end of Year 1. The Company shall track the total amount collected through Year 1 and Year 2 and true up in Year 3. In Year 3, this surcharge may continue at a revised rate, subject to subsequent Commission review and approval, in order to reflect any undercollection or overcollection of the total authorized surcharge amount.

Voltage Level	Year 1	Year 2
Secondary - less than 2,300 volts	0.8585 ¢	0.4200 ¢
Primary - 2,300 to 44,000 volts	0.8326 ¢	0.4073 ¢
Transmission - over 44,000 volts	0.8151 ¢	0.3988 ¢

Table BB1

UTAH POWER
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
NORMALIZED 12 MONTHS ENDED MARCH 2001

						Current Revenues ($000)				Proposed Yr1 RMA		Proposed Yr1 PCS		Exclusive of Sch. 34				Proposed Sch. 34		Inclusive of Sch. 34			
Line No.	Account No.	Description	Sch. No.	Average No. of Customers	MWh	Base Rev.	Merger Credit	Sch. 34 Credit	Net Rev.	Rev. ($000)	¢/kWh	Rev. ($000)	%	Total Rev. ($000)	Change ($000)	Change %	Change ¢/kWh	Credit ($000)	%	Total Rev. ($000)	Change ($000)	Change %	Change ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) (6)+(7)+(8)	(10)	(11) (10)/(5)	(12)	(13) (12)/(6)	(14) (6)+(10)+(12)	(15) (14)-(6)-(7)	(16) (15)/[(6)+(7)]	(17) (15)/(5)	(18)	(19) (18)/[(6)+(7)]	(20) (14)+(18)	(21) (20)-(9)	(22) (21)/(9)	(23) (21)/(5)
	440	**Residential Sales**																					
1		Residential Service	1	28,524	257,880	$22,056	($375)	($951)	$20,730	$0	0.0000	$2,214	10.04%	$24,270	$2,589	11.9%	1.004	($8,619)	-39.75%	$15,651	($5,079)	-24.5%	-1.970
2		Residential Optional TOD	36	15,933	303,528	$20,383	($347)	($1,039)	$18,997	$0	0.0000	$2,606	12.79%	$22,989	$2,953	14.7%	0.973	($10,132)	-50.57%	$12,857	($6,140)	-32.3%	-2.023
3		**Total Residential**		44,457	561,408	$42,439	($722)	($1,990)	$39,727	$0		$4,820	11.36%	$47,259	$5,542	13.3%	0.987	($18,751)	-44.95%	$28,508	($11,219)	-28.2%	-1.998
	442	**Commercial & Industrial**																					
4		General Service - Large Power	6	927	241,884	$13,571	($231)		$13,340	($1,759)	-0.7272	$2,068	15.24%	$13,880	$540	4.0%	0.223	$0	0.00%	$13,880	$540	4.0%	0.223
5		General Svc. - Lg. Power (R&F)	6A	222	28,149	$1,761	($30)	($93)	$1,638	$0	0.0000	$242	13.74%	$2,003	$272	15.7%	0.966	($929)	-53.67%	$1,074	($564)	-34.4%	-2.004
6		General Service - Med. Voltage	8	4	2,816	$156	($3)		$153	($21)	-0.7457	$24	15.38%	$159	$6	3.9%	0.213	$0	0.00%	$159	$6	3.9%	0.213
7		General Service - High Voltage	9	14	104,022	$4,373	($74)		$4,299	($750)	-0.7210	$848	19.39%	$4,471	$172	4.0%	0.165	$0	0.00%	$4,471	$172	4.0%	0.165
8		Irrigation Rate	10	1,876	615,632	$32,327	($550)	($5,578)	$26,199	$4,000	0.6497	$5,285	16.35%	$41,612	$9,835	31.0%	1.598	($20,344)	-64.02%	$21,268	($4,931)	-18.8%	-0.801
9		Comm. & Ind. Space Heating	19	346	13,338	$942	($16)		$926	($94)	-0.7048	$115	12.21%	$963	$37	4.0%	0.277	$0	0.00%	$963	$37	4.0%	0.277
10		General Service	23	4,591	85,932	$7,410	($126)		$7,284	($570)	-0.6633	$737	9.95%	$7,577	$293	4.0%	0.341	$0	0.00%	$7,577	$293	4.0%	0.341
11		General Service (R&F)	23A	1,310	16,388	$1,468	($25)	($53)	$1,390	$0	0.0000	$141	9.60%	$1,609	$166	11.5%	1.013	($540)	-37.42%	$1,069	($321)	-23.1%	-1.959
12		General Service Optional TOD	35	1	1,227	$52	($1)		$51	($10)	-0.8150	$11	21.15%	$53	$2	3.9%	0.163	$0	0.00%	$53	$2	3.9%	0.163
13		**Total Commercial & Industrial**		9,291	1,109,388	$62,060	($1,056)	($5,724)	$55,280	$796		$9,471	15.26%	$72,327	$11,323	18.6%	1.021	($21,813)	-35.76%	$50,514	($4,766)	-8.6%	-0.430
	444	**Public Street Lighting**																					
14		Security Area Lighting	7	245	288	$72	($1)		$71	($2)	-0.6944	$3	4.17%	$73	$2	2.8%	0.694	$0	0.00%	$73	$2	2.8%	0.694
15		Security Area Lighting (R&F)	7A	181	141	$38	($1)	($1)	$36	$0	0.0000	$1	2.63%	$39	$2	5.4%	1.418	($5)	-13.51%	$34	($2)	-5.6%	-1.418
16		Street Lighting - Company	11	29	137	$41	($1)		$40	($1)	-0.7299	$1	2.44%	$41	$1	2.5%	0.730	$0	0.00%	$41	$1	2.5%	0.730
17		Street Lighting - Customer	12	161	1,919	$251	($4)		$247	($14)	-0.7295	$17	6.77%	$254	$7	2.8%	0.365	$0	0.00%	$254	$7	2.8%	0.365
18		Traffic Signal Systems	12	21	224	$23	$0		$23	($2)	-0.8929	$2	8.70%	$23	$0	0.0%	0.000	$0	0.00%	$23	$0	0.0%	0.000
19		**Total Public Street Lighting**		637	2,709	$425	($7)	($1)	$417	($19)		$24	5.65%	$430	$12	2.9%	0.443	($5)	-1.20%	$425	$8	1.9%	0.295
20		**Total Sales to Ultimate Consumers**		54,385	1,673,505	$104,924	($1,785)	($7,715)	$95,424	$777		$14,315	13.64%	$120,016	$16,877	16.4%	1.008	($40,569)	-39.33%	$79,447	($15,977)	-16.7%	(0.955)

Table BB2

UTAH POWER
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
NORMALIZED 12 MONTHS ENDED MARCH 2001

Line No.	Account No. (1)	Description (2)	Sch. No. (3)	Average No. of Customers (4)	MWh (5)	End of Yr 1 ($000) Base Current Rev. (6)	End of Yr 1 ($000) Yr 1 RMA + PCS (7)	End of Yr 1 ($000) Yr 1 Sch. 34 Credit (8)	End of Yr 1 ($000) Net Rev. (9) (6)+(7)+(8)	Proposed Yr 2 RMA Rev. ($000) (10)	Proposed Yr 2 RMA ¢/kWh (11) (10)/(5)	Proposed Yr 2 PCS Rev. ($000) (12)	Proposed Yr 2 PCS % (13) (12)/(6)	Exclusive of Sch. 34 Total Rev. ($000) (14) (6)+(10)+(12)	Exclusive of Sch. 34 Change ($000) (15) (14)-(6)-(7)	Exclusive of Sch. 34 Change % (16) (15)/((6)+(7))	Exclusive of Sch. 34 Change ¢/kWh (17) (15)/(5)	Proposed Yr2 Sch. 34 Credit ($000) (18)	Proposed Yr2 Sch. 34 % (19) (18)/((6)+(7))	Inclusive of Sch. 34 Total Rev. ($000) (20) (14)+(18)	Inclusive of Sch. 34 Change ($000) (21) (20)-(9)	Inclusive of Sch. 34 Change % (22) (21)/(9)	Inclusive of Sch. 34 Change ¢/kWh (23) (21)/(5)	Total Change From Current ($000) (24) (20)-(A1(9))	Total Change From Current % (25) (24)/(A1(9))
	440	**Residential Sales**																							
1		Residential Service	1	28,524	257,880	$22,056	$2,214	($8,619)	$15,651	($1,039)	-0.4029	$1,083	4.91%	$22,100	($2,170)	-8.9%	-0.841	($6,449)	-26.57%	$15,651	$0	0.0%	0.000	($5,079)	-24.5%
2		Residential Optional TOD	36	15,933	303,528	$20,383	$2,606	($10,132)	$12,857	($1,220)	-0.4019	$1,275	6.26%	$20,438	($2,551)	-11.1%	-0.840	($7,581)	-32.98%	$12,857	$0	0.0%	0.000	($6,140)	-32.3%
3		**Total Residential**		44,457	561,408	$42,439	$4,820	($18,751)	$28,508	($2,259)		$2,358	5.56%	$42,538	($4,721)	-10.0%	-0.841	($14,030)	-29.69%	$28,508	$0	0.0%	0.000	($11,219)	-28.2%
	442	**Commercial & Industrial**																							
4		General Service - Large Power	6	927	241,884	$13,571	$309	$0	$13,880	($702)	-0.2902	$1,011	7.45%	$13,880	$0	0.0%	0.000	$0	0.00%	$13,880	$0	0.0%	0.000	$540	4.0%
5		General Svc. - Lg. Power (R&F)	6A	222	28,149	$1,761	$242	($929)	$1,074	($110)	-0.3908	$118	6.70%	$1,769	($234)	-11.7%	-0.831	($695)	-34.70%	$1,074	$0	0.0%	0.000	($564)	-34.4%
6		General Service - Med. Voltage	8	4	2,816	$156	$3	$0	$159	($9)	-0.3196	$12	7.69%	$159	$0	0.0%	0.000	$0	0.00%	$159	$0	0.0%	0.000	$6	3.9%
7		General Service - High Voltage	9	14	104,022	$4,373	$98	$0	$4,471	($315)	-0.3028	$415	9.49%	$4,473	$2	0.0%	0.002	$0	0.00%	$4,473	$2	0.0%	0.002	$174	4.0%
8		Irrigation Rate	10	1,876	615,632	$32,327	$9,285	($20,344)	$21,268	$4,000	0.6497	$2,586	8.00%	$38,913	($2,699)	-6.5%	-0.438	($20,058)	-48.20%	$18,855	($2,413)	-11.3%	-0.392	($7,344)	-28.0%
9		Comm. & Ind. Space Heating	19	346	13,338	$942	$21	$0	$963	($35)	-0.2624	$56	5.94%	$963	$0	0.0%	0.000	$0	0.00%	$963	$0	0.0%	0.000	$37	4.0%
10		General Service	23	4,591	85,932	$7,410	$167	$0	$7,577	($194)	-0.2258	$361	4.87%	$7,577	$0	0.0%	0.000	$0	0.00%	$7,577	$0	0.0%	0.000	$293	4.0%
11		General Service (R&F)	23A	1,310	16,388	$1,468	$141	($540)	$1,069	($64)	-0.3905	$69	4.70%	$1,473	($136)	-8.5%	-0.830	($404)	-25.11%	$1,069	$0	0.0%	0.000	($321)	-23.1%
12		General Service Optional TOD	35	1	1,227	$52	$1	$0	$53	($4)	-0.3260	$5	9.62%	$53	$0	0.0%	0.000	$0	0.00%	$53	$0	0.0%	0.000	$2	3.9%
13		**Total Commercial & Industrial**		9,291	1,109,388	$62,060	$10,267	($21,813)	$50,514	$2,567		$4,633	7.47%	$69,260	($3,067)	-4.2%	-0.276	($21,157)	-29.25%	$48,103	($2,411)	-4.8%	-0.217	($7,177)	-12.1%
	444	**Public Street Lighting**																							
14		Security Area Lighting	7	245	288	$72	$1	$0	$73	$0	0.0000	$1	1.39%	$73	$0	0.0%	0.000	$0	0.00%	$73	$0	0.0%	0.000	$2	2.8%
15		Security Area Lighting (R&F)	7A	181	141	$38	$1	($5)	$34	($1)	-0.7092	$1	2.63%	$38	($1)	-2.6%	-0.709	($4)	-10.26%	$34	$0	0.0%	0.000	($2)	-5.6%
16		Street Lighting - Company	11	29	137	$41	$0	$0	$41	($1)	-0.7299	$1	2.44%	$41	$0	0.0%	0.000	$0	0.00%	$41	$0	0.0%	0.000	$1	2.5%
17		Street Lighting - Customer	12	161	1,919	$251	$3	$0	$254	($6)	-0.3127	$8	3.19%	$253	($1)	-0.4%	-0.052	$0	0.00%	$253	($1)	-0.4%	-0.052	$6	2.4%
18		Traffic Signal Systems	12	21	224	$23	$0	$0	$23	($1)	-0.4464	$1	4.35%	$23	$0	0.0%	0.000	$0	0.00%	$23	$0	0.0%	0.000	$0	0.0%
19		**Total Public Street Lighting**		637	2,709	$425	$5	($5)	$425	($9)		$12	2.82%	$428	($2)	-0.5%	-0.074	($4)	-0.93%	$424	($1)	-0.2%	-0.037	$7	1.7%
20		**Total Sales to Ultimate Consumers**		54,385	1,673,505	$104,924	$15,092	($40,569)	$79,447	$299		$7,003	6.67%	$112,226	($7,790)	-6.5%	(0.465)	($35,191)	-29.32%	$77,035	($2,412)	-3.0%	(0.144)	($18,389)	-18.5%

Table BB3

UTAH POWER
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
NORMALIZED 12 MONTHS ENDED MARCH 2001

Line No.	Account No.	Description	Sch. No.	Average No. of Customers	MWh	End of Yr 2 ($000) Base Current Rev.	End of Yr 2 ($000) Yr 2 RMA + PCS	End of Yr 2 ($000) Yr 2 Sch. 34 Credit	End of Yr 2 ($000) Net Rev.	Proposed Yr 3 RMA Rev. ($000)	Proposed Yr 3 RMA ¢/kWh	Proposed Yr 3 PCS Rev. ($000)	Proposed Yr 3 PCS %	Exclusive of Sch. 34 Total Rev. ($000)	Exclusive of Sch. 34 Change ($000)	Exclusive of Sch. 34 Change %	Exclusive of Sch. 34 Change ¢/kWh	Proposed Yr3 Sch. 34 Credit ($000)	Proposed Yr3 Sch. 34 %	Inclusive of Sch. 34 Total Rev. ($000)	Inclusive of Sch. 34 Change ($000)	Inclusive of Sch. 34 Change %	Inclusive of Sch. 34 Change ¢/kWh	Total Change From Current ($000)	Total Change From Current %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) (6)+(7)+(8)	(10)	(11) (10)/(5)	(12)	(13) (12)/(6)	(14) (6)+(10)+(12)	(15) (14)-(6)-(7)	(16) (15)/((6)+(7))	(17) (15)/(5)	(18)	(19) (18)/((6)+(7))	(20) (14)+(18)	(21) (20)-(9)	(22) (21)/(9)	(23) (21)/(5)	(24) (20)-(A1(9))	(25) (24)/(A1(9))
	440	**Residential Sales**																							
1		Residential Service	1	28,524	257,880	$22,056	$44	($6,449)	$15,651	($1,798)	-0.6972	$49	0.22%	$20,307	($1,793)	-8.1%	-0.695	($6,449)	-29.18%	$13,858	($1,793)	-11.5%	-0.695	($6,872)	-33.2%
2		Residential Optional TOD	36	15,933	303,528	$20,383	$55	($7,581)	$12,857	($732)	-0.2412	$58	0.28%	$19,709	($729)	-3.6%	-0.240	($7,581)	-37.09%	$12,128	($729)	-5.7%	-0.240	($6,869)	-36.2%
3		**Total Residential**		44,457	561,408	$42,439	$99	($14,030)	$28,508	($2,530)		$107	0.25%	$40,016	($2,522)	-5.9%	-0.449	($14,030)	-32.98%	$25,986	($2,522)	-8.8%	-0.449	($13,741)	-34.6%
	442	**Commercial & Industrial**																							
4		General Service - Large Power	6	927	241,884	$13,571	$309	$0	$13,880	$0	0.0000	$45	0.33%	$13,616	($264)	-1.9%	-0.109	$0	0.00%	$13,616	($264)	-1.9%	-0.109	$276	2.1%
5		General Svc. - Lg. Power (R&F)	6A	222	28,149	$1,761	$8	($695)	$1,074	$0	0.0000	$5	0.28%	$1,766	($3)	-0.2%	-0.011	($695)	-39.29%	$1,071	($3)	-0.3%	-0.011	($567)	-34.6%
6		General Service - Med. Voltage	8	4	2,816	$156	$3	$0	$159	$7	0.2486	$1	0.64%	$164	$5	3.1%	0.178	$0	0.00%	$164	$5	3.1%	0.178	$11	7.2%
7		General Service - High Voltage	9	14	104,022	$4,373	$100	$0	$4,473	$0	0.0000	$19	0.43%	$4,392	($81)	-1.8%	-0.078	$0	0.00%	$4,392	($81)	-1.8%	-0.078	$93	2.2%
8		Irrigation Rate	10	1,876	615,632	$32,327	$6,586	($20,058)	$18,855	$4,000	0.6497	$117	0.36%	$36,444	($2,469)	-6.3%	-0.401	($20,058)	-51.55%	$16,386	($2,469)	-13.1%	-0.401	($9,813)	-37.5%
9		Comm. & Ind. Space Heating	19	346	13,338	$942	$21	$0	$963	($86)	-0.6448	$3	0.32%	$859	($104)	-10.8%	-0.780	$0	0.00%	$859	($104)	-10.8%	-0.780	($67)	-7.2%
10		General Service	23	4,591	85,932	$7,410	$167	$0	$7,577	($1,106)	-1.2871	$16	0.22%	$6,320	($1,257)	-16.6%	-1.463	$0	0.00%	$6,320	($1,257)	-16.6%	-1.463	($964)	-13.2%
11		General Service (R&F)	23A	1,310	16,388	$1,468	$5	($404)	$1,069	($173)	-1.0557	$3	0.20%	$1,298	($175)	-11.9%	-1.068	($404)	-27.43%	$894	($175)	-16.4%	-1.068	($496)	-35.7%
12		General Service Optional TOD	35	1	1,227	$52	$1	$0	$53	$0	0.0000	$0 *	0.00%	$52	($1)	-1.9%	-0.081	$0	0.00%	$52	($1)	-1.9%	-0.081	$1	2.0%
13		**Total Commercial & Industrial**		9,291	1,109,388	$62,060	$7,200	($21,157)	$48,103	$2,642		$209	0.34%	$64,911	($4,349)	-6.3%	-0.392	($21,157)	-30.55%	$43,754	($4,349)	-9.0%	-0.392	($11,526)	-19.4%
	444	**Public Street Lighting**																							
14		Security Area Lighting	7	245	288	$72	$1	$0	$73	($19)	-6.5972	$0 *	0.00%	$53	($20)	-27.4%	-6.944	$0	0.00%	$53	($20)	-27.4%	-6.944	($18)	-25.4%
15		Security Area Lighting (R&F)	7A	181	141	$38	$0	($4)	$34	($9)	-6.3830	$0 *	0.00%	$29	($9)	-23.7%	-6.383	($4)	-10.53%	$25	($9)	-26.5%	-6.383	($11)	-30.6%
16		Street Lighting - Company	11	29	137	$41	$0	$0	$41	($11)	-8.0292	$0 *	0.00%	$30	($11)	-26.8%	-8.029	$0	0.00%	$30	($11)	-26.8%	-8.029	($10)	-25.0%
17		Street Lighting - Customer	12	161	1,919	$251	$2	$0	$253	($67)	-3.4914	$0 *	0.00%	$184	($69)	-27.3%	-3.596	$0	0.00%	$184	($69)	-27.3%	-3.596	($63)	-25.5%
18		Traffic Signal Systems	12	21	224	$23	$0	$0	$23	($6)	-2.6786	$0 *	0.00%	$17	($6)	-26.1%	-2.679	$0	0.00%	$17	($6)	-26.1%	-2.679	($6)	-26.1%
19		**Total Public Street Lighting**		637	2,709	$425	$3	($4)	$424	($112)		$0 *	0.00%	$313	($115)	-26.9%	-4.245	($4)	-0.93%	$309	($115)	-27.1%	-4.245	($108)	-25.9%
20		**Total Sales to Ultimate Consumers**		54,385	1,673,505	$104,924	$7,302	($35,191)	$77,035	$0		$316	0.30%	$105,240	($6,986)	-6.2%	(0.417)	($35,191)	-31.36%	$70,049	($6,986)	-9.1%	(0.417)	($25,375)	-25.5%

* Less than $1,000.

utah power & LIGHT COMPANY

UTAH POWER & LIGHT COMPANY

ELECTRIC SERVICE SCHEDULE NO. 10

STATE OF IDAHO

Irrigation and Soil Drainage Pumping Power Service

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity.

APPLICATION: This Schedule is for alternating current, single or three-phase electric service supplied at the Company's available voltage through a single point of delivery for service to motors on pumps and machinery used for irrigation and soil drainage.

IRRIGATION SEASON AND POST-SEASON SERVICE: The Irrigation Season is from June 1 (C) to September 15 each year. Service for post-season pumping may be taken by the same Customer at the same point of delivery and through the same facilities used for supplying regular irrigation pumping service during months from September 16 to the following May 31.

MONTHLY BILL:

Irrigation Season Rate (N)

Customer Service Charge:

Small Pumping Operations:

15 horsepower or less total connected horsepower served through one service connection - $10.17 per Customer

Large Pumping Operations:

16 horsepower or more total connected horsepower served through one service connection - $30.33 per Customer (N)

(Continued)

ELECTRIC SERVICE SCHEDULE No. 10 - Continued

MONTHLY BILL: (Continued) (N)

Power Rate: $4.05 per kW for all kW

Energy Rate: 5.4320¢ per kWh for first 25,000 kWh
3.8024¢ per kWh for the next 225,000 kWh
2.5000¢ per kWh for all additional kWh

Power Factor: This rate is based on the Customer maintaining at all times a power factor of 85% lagging, or higher, as determined by measurement. If the average power factor is found to be less than 85% lagging, the power as recorded by the Company's meter will be increased by 3/4 of 1% for every 1% that the power factor is less than 85%.

Minimum: The Customer Service Charge. (N)

Post-Season Rate (C)

Customer Service Charge: $16.17 per Customer
Energy Rate: 4.5059¢ per kWh for all kWh (I)

Minimum: The Customer Service Charge.

ADJUSTMENTS: All monthly bills shall be adjusted in accordance with Schedules 34, 93 and 94. (N) (C)

PAYMENT: All monthly service billings will be due and payable when rendered and will be considered delinquent if not paid within fifteen (15) days. An advance payment may be required of the Customer by the Company in accordance with Electric Service Regulation No. 9. An advance may be required under any of the following conditions:

(1) the Customer failed to pay all amounts owed to the Company when due and payable;

(2) the Customer paid an advance the previous season that did not adequately cover bills for the entire season and the Customer failed to pay any balance owing by the due date of the final billing issued for the season.

(Continued)

ELECTRIC SERVICE SCHEDULE No. 10 - Continued

(C)

PAYMENT: (continued)

An adequate assurance of payment (advance) may be required from a Customer who has filed bankruptcy. Advances which may be required of the Customer may be paid with cash payment or guarantee, as required by the Company, or with a letter of escrow acceptable to the Company from an authorized bank in the Company's service area. This letter of escrow shall provide that upon termination of service to the Customer, the Company shall receive, upon demand, cash equal to the unpaid balance of the Customer's bill which is not disputed or the full amount of the advance, whichever is the lesser amount.

CONNECTION AND DISCONNECTION CHARGES: Company will not routinely seasonally connect and disconnect service to irrigation pumps. However, upon oral or written request the Company will connect and disconnect service at the beginning and end of Customer's pumping operation each year without charge. Customer shall give Company at least two (2) weeks advance notice of the date disconnection and connection of seasonal service is desired. The actual expense incurred for additional connection and disconnection shall be paid by Customer. Customer shall give Company at least two (2) weeks advance notice of the date any additional connection and/or an additional disconnection of service is desired. Meters will not be read and bills will not be issued from November 1 to March 1 unless the customer requests in writing a different ending or beginning point for billing. The bill issued in March will include charges for any unbilled energy used during the period of November 1 to March 1.

POWER: The kW as shown by or computed from the readings of the Company's power meter for the 15-minute period of Customer's greatest use during the month, adjusted for power factor as specified, determined to the nearest kW. Metered power demands in kilowatts which exceed one hundred and thirty percent (130%) of the total connected horsepower served through one service connection will not be used for billing purposes unless and until verified by field test in the presence of the Company to be the result of normal pumping operations. If a demand in excess of 130% of connected horsepower is the result of abnormal conditions existing on the Company's interconnected system or the Customer's system, including accidental equipment failure or electrical supply interruption which results in temporary separation of the Company and Customer's system, the billing demand shall be 130% of the connected horsepower. The Customer may appeal the Company's billing decision to the Idaho Public Utilities Commission in cases of dispute.

CONTRACT PERIOD: One year or longer.

(Continued)

Attachment C

utah power & LIGHT COMPANY

I.P.U.C. No. 28

Fifth Revised Sheet No. 10.4
Canceling Fourth Revised Sheet No. 10.4

ELECTRIC SERVICE SCHEDULE No. 10 - Continued

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Idaho Public Utilities Commission, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

Submitted Under Case No. PAC-E-02-1

ISSUED: April 10, 2002 **EFFECTIVE:** May 15, 2002

utah power & LIGHT COMPANY

UTAH POWER & LIGHT COMPANY

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

RATE MITIGATION ADJUSTMENT

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the terms contained in this Tariff.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt-hour. The prices in the column labeled "Year 1" shall be in effect for one year beginning on the effective date of this tariff. The prices in the column labeled "Year 2" shall be in effect for one year beginning at the end of Year 1. The prices in the column labeled "Year 3 and Subsequent Years" shall be in effect beginning at the end of Year 2.

		Year 1	Year 2	Year 3 and Subsequent Years
Schedule	1	0.0000 ¢	(0.4029) ¢	(0.6972) ¢
Schedule	6	(0.7272) ¢	(0.2902) ¢	0.0000 ¢
Schedule	6A	0.0000 ¢	(0.3908) ¢	0.0000 ¢
Schedule	7	(0.6944) ¢	0.0000 ¢	(6.5972) ¢
Schedule	7A	0.0000 ¢	(0.7092) ¢	(6.3830) ¢
Schedule	8	(0.7457) ¢	(0.3196) ¢	0.2486 ¢
Schedule	9	(0.7210) ¢	(0.3028) ¢	0.0000 ¢
Schedule	10	0.6497 ¢	0.6497 ¢	0.6497 ¢
Schedule	11	(0.7299) ¢	(0.7299) ¢	(8.0292) ¢
Schedule	12 - Street Lighting	(0.7295) ¢	(0.3127) ¢	(3.4914) ¢
Schedule	12 - Traffic Signal	(0.8929) ¢	(0.4464) ¢	(2.6786) ¢
Schedule	19	(0.7048) ¢	(0.2624) ¢	(0.6448) ¢
Schedule	23	(0.6633) ¢	(0.2258) ¢	(1.2871) ¢
Schedule	23A	0.0000 ¢	(0.3905) ¢	(1.0557) ¢
Schedule	35	(0.8150) ¢	(0.3260) ¢	0.0000 ¢
Schedule	36	0.0000 ¢	(0.4019) ¢	(0.2412) ¢
Schedule	400 - Nu-West	(0.6764) ¢	(0.2603) ¢	0.0000 ¢