Q. Please state your name and business address for the record.

A. My name is Randy Lobb and my business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed?

A. I am employed by the Idaho Public Utilities Commission as Utilities Division Administrator.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Agricultural Engineering from the University of Idaho in 1980 and worked for the Idaho Department of Water Resources from June of 1980 to November of 1987. I received my Idaho license as a registered professional Civil Engineer in 1985 and began work at the Idaho Public Utilities Commission in December of 1987. My duties at the Commission currently include case management and oversight of all technical staff assigned to Commission filings. I have conducted analysis of utility rate applications, rate design, tariff analysis and customer petitions. I have testified in numerous proceedings before the Commission including cases dealing with rate structure, cost of service, power supply, line extensions and facility acquisitions.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to describe the provisions of the Stipulated Settlement presented to the Commission in this case and attached as Staff Exhibit No. 101. I will also discuss the issues considered in negotiating and developing the agreement and support Staff's recommendation for Settlement approval.

Q. Would you please summarize your testimony?

A. Yes. The tendered Stipulation is the end result of comprehensive negotiations by the parties to this case. The Stipulation incorporates implementation of the BPA credit, reasonable recovery of extraordinary power supply costs with mitigation, modified revenue requirement across customer classes and changes in irrigation rate design. The Settlement package incorporates an extraordinary BPA credit agreement and allows reasonable recovery of extraordinary power supply costs. The Settlement utilizes a modified irrigation class revenue requirement that more accurately reflects cost of service to significantly reduce rate increases in other classes that would otherwise occur due to power supply cost recovery.

The Settlement negotiations focused on three main areas: 1) power supply cost recovery amount, 2) customer class revenue requirement, and 3) rate design.

The primary issues addressed by the parties in the cost recovery negotiations centered around those issues identified by the Commission including the Idaho jurisdictional revenue requirement, the merger condition prohibiting a rate increase for two years, the Hunter generating plant outage and the effect of wholesale sales contracts and load growth on power supply costs. After evaluation of these issues and numerous discussions with all parties, Staff believes that a 65% recovery of the deferred power supply costs is appropriate and fair to both the Company and its Idaho customers.

The second phase of the negotiations dealt with the determination of the appropriate annual revenue requirement for each customer class. Staff believes that the Settlement properly incorporates the previously approved BPA credit and reasonably adjusts the irrigation revenue requirement to better reflect cost of service. More importantly, the Settlement effectively reduces the impact of power supply cost recovery by applying a revenue (rate) mitigation adjustment to various customer classes and spreading recovery over two years. The net change in annual revenue requirement (as compared to 2001) ranges between a 34% decrease in one customer class to a maximum 4% increase in other classes.

Finally, Staff supports adjusting the energy component of rates in each class (where appropriate) to reflect a combination of BPA credit, a power supply surcharge and a rate mitigation adjustment. Staff further supports modification of the rate structure in the irrigation class to establish a single low cost firm rate and a declining block energy rate for large irrigators.

POWER SUPPLY COSTS

Q. What issues did Staff consider in evaluating the Company's request to recover deferred extraordinary power supply costs?

A. Staff focused on four main issues in its evaluation of the Company's request. They included: 1) a determination of the appropriate Idaho jurisdictional power supply costs on a normalized basis; 2) an evaluation and audit of Idaho jurisdictional power supply costs during the deferral period; 3) the economic impact and propriety of wholesale power sales contracts, and 4) the economic impact and circumstances surrounding the failure of the Hunter coal fire generating station.

Q. How did Staff determine what issues to address?

A. Staff issues were identified during its case review and audit and established by the Commission in its Notice of Issues and Scheduling in this case. The nature of the extraordinary system power supply costs that the

Company is seeking to recover and the methodology used to allocate those costs to Idaho were main factors considered when framing the issues. For example, higher than normal power purchase costs and lower than normal surplus sales comprised the vast majority of the extraordinary system costs. Therefore, Staff focused on resource availability and load obligations.

Resource availability was diminished by abnormally low water conditions and the loss of the Hunter generating plant. Replacement resources were essentially limited to energy purchases from the market at extraordinarily high prices. Load obligations included normalized native load, growth in native load and long-term firm wholesale sales contracts. Hunter operation and the magnitude of wholesale sales are under the direct control of the Company. During the audit, these areas were identified as the main focus of Staff’s investigation. Once the level of system costs was established, methods used to allocate those costs to Idaho were reviewed and compared to past practices to assure consistency.

Q. Why didn’t Staff oppose recovery based on Scottish Power/PacifiCorp Merger Approval Condition No. 2 that prohibited rate increases for two years?

A. Staff believed that the merger language was clear. It stated: "As a minimum, Scottish Power shall not seek a general rate increase for its Idaho service territory effective prior to January 1, 2002."

Based on this language, Staff believed that rates could increase after January 1, 2002. Staff further understood as part of its participation in the merger negotiations that rate stability through 2001 was the objective of the condition and the use of costs incurred during 2001 to establish rates after January 1, 2002, was not prohibited. Staff also considered the extraordinary market conditions and the fact that PacifiCorp does not control the market as a legitimate reason for power cost deferral and recovery.

The Commission has subsequently issued Order No. 28998 establishing that the merger condition does not prohibit recovery of deferred power supply costs after January 2, 2002.

Q. Based on its review of the main issues cited above, what cost recovery adjustment did Staff believe was justified prior to Settlement negotiations?

A. As a starting point to the negotiations, Staff originally proposed that approximately $21 million in deferred power supply costs be recovered from the Idaho jurisdiction. This represents a reduction of about $17 million in the amount requested for recovery by the

Company.

Q. What adjustments were specifically identified?

A. As shown on Staff Exhibit No. 102, Staff adjustments specifically included a reduction in the base jurisdictional allocation to Idaho of $3.2 million in 1998 net power costs consistent with previous Staff recommendations in Case No. PAC-E-00-5. Staff also maintained that interest of about $900,000 on the deferral balance should be removed in addition to removal of $600,000 to reflect the additional costs of normal load growth included by the Company as an extraordinary power supply cost.

Staff proposed that $1.5 million for two wholesale power contracts be remove from the total deferred power costs based on contract charges. Nine other wholesale sales contracts signed after 1994 were considered under priced. Consistent with prior audit adjustments, one contract has 100% of the revenue imputed for an adjustment of $400,000. Imputation of revenue for the remaining contracts at the 1998 marginal cost of service resulted in an adjustment of approximately $15.2 million. Staff believed that a 50% sharing of the imputed revenue reflected a reasonable sharing of costs and risk associated with the contracts. A 50% sharing of the $1 million costs and risks associated with wheeling for non-native load contracts was also believed to be a reasonable sharing of cost risk associated with discretionary transactions.

Q. Did Staff propose any adjustment in cost recovery associated with the outage at the Hunter coal fired generating station?

A. Yes. Staff determined that the cost associated with the Hunter outage represented approximately $11.9 million of the total $38.3 million in extraordinary power supply costs requested for recovery by the Company. Based on a review of expert testimony filed in other jurisdictions regarding this issue, it is unclear exactly what role, if any, maintenance schedules, monitoring equipment and operating protocols had in the failure of the Hunter generator. Based on its review, Staff believed that the Company had some responsibility in the failure and should share responsibility for a portion of the extraordinary costs. Therefore, Staff proposed that the Hunter cost recovery be reduced by 25% or $3 million.

Q. What costs were included in the Hunter outage total?

A. The costs included were essentially the net costs above and beyond what would have occurred had Hunter operated normally. While fuel costs to operate Hunter were obviously eliminated, the Company was forced to buy replacement energy from the market at a time when prices were extraordinarily high. The costs do not include the costs to repair the plant.

Q. What amount of extraordinary power supply expense did the parties ultimately agree to?

A. The parties ultimately agreed to allow recovery of $25 million in extraordinary power supply costs or approximately 65% of the original request.

Q. How did Staff determine what adjustments to propose and what level constituted a reasonable settlement?

A. Staff reviewed filed testimony and orders issued in other jurisdictions that dealt with wholesale contracts and the Hunter outage. Staff also carefully reviewed past Company filings and Staff recommendations to establish a reasonable level of normalized power supply costs allocated to Idaho. Staff then evaluated the components of the deferred power supply costs to identify what costs were extraordinary, to determine what events caused the extraordinary costs and to establish responsibility for cost recovery.

The determination of what constituted a reasonable adjustment for each power supply issue and what constituted a reasonable overall settlement was made based primarily upon Staff's evaluation of how successful it would be in presenting and defending its positions at hearing. Discussing the merits of the various issues with other parties to the negotiation and evaluating the resources required to litigate in Idaho the same issues already addressed in other jurisdiction also shaped Staff's position. Finally, Staff saw an opportunity to significantly reduce the impact of power supply cost recovery for customers by packaging the recovery with the BPA credit and movement in irrigator revenue requirement to more closely reflect cost of service.

Q. Does the Settlement specifically establish the exact adjustment required for each issue?

A. No. The Settlement establishes an overall adjustment to the Company's request. The cost responsibility for the Hunter outage or any of the other issues was not specifically identified as part of the Stipulation.

Q. Why were the remaining two years of the merger credit accelerated and included in the Stipulated Settlement?

A. The remaining two years of the merger credit, valued at $2.3 million, was included to further reduce the impact of power supply cost recovery and eliminate the need for a rate increase when the merger credit expires at the end of 2003.

CLASS REVENUE REQUIREMENT

Q. Once an agreement was reached on a reasonable level of power supply cost recovery, how did Staff and the other parties establish an equitable spreading of revenue requirement among the customer classes?

A. Staff's objective was to create a package that appropriately applied the BPA credit, equitably distributed the power supply cost recovery responsibility and ultimately moved the irrigation class closer to cost of service. Most importantly, Staff's objective was to achieve this result with the smallest possible increase in customer rates.

Q. Was Staff able to achieve its desired result?

A. Yes, we believe that we have. All of the objectives were reasonably achieved and no customer class received a rate increase greater than 4% over the two-year period. While Staff does not wish to minimize the impact of a 4% increase, we also recognize that rate increases due to recent extraordinary events have been much higher for many other electric customers throughout the region. In addition, without the class rate mitigation provided by the Stipulation, the rate impact resulting from what we believe is reasonable power supply cost recovery could have exceeded 17% for some customers over a two-year period.

Q. What do you mean by rate mitigation and how was it achieved?

A. Rate mitigation is simply a credit used to reduce the energy rate of a given customer class that would otherwise experience a larger rate increase. Increasing the revenue requirement assigned to the irrigation class and distributing the savings to classes that experience an increase during the power supply cost recovery period provided rate mitigation. Rate mitigation was also provided in year two to assure that no customer class experiences any rate increase as compared to the prior year.

Q. Why did you increase the revenue requirement assigned to the irrigation class?

A. Based on the last cost of service study approved by the Commission in 1990 and several cost of service studies submitted since then including the one submitted by the Company in this case, the irrigation class has generated revenues significantly below that required to cover cost of service. The result is a subsidy of the irrigation class by other customer classes. The extraordinarily large BPA credit provided a valuable opportunity to modify the irrigation class revenue requirement without increasing average irrigation rates. Modifying the revenue requirement at this time reduces the subsidy, reduces the effect on irrigation rates that would have occurred without the BPA credit and provides an opportunity to provide rate mitigation to reduce the effects on other classes of extraordinary power supply cost recovery.

Because movement in class revenue requirement must be revenue neutral outside of a general rate case, the level of mitigation had to exactly equal the $4 million increase in irrigation revenue requirement. After power supply costs are recovered in full, rate mitigation will continue to reflect a continuation of class revenue requirement that more closely reflects costs of service.

Q. Does Staff agree with the cost of service study submitted by the Company in this case?

A. No. Staff did not accept the specific details of the cost of service study submitted by the Company and required that the position be so stated in the Stipulation. Staff did agree that an increase in irrigation revenue requirement at this time represents a reasonable step toward what will ultimately be accepted as cost of service. Staff will evaluate specific cost of service issues and make its recommendations to the Commission in conjunction with Case No. PAC-E-01-19 (The Monsanto/PacifiCorp Service Contract Case). The cost of service study ultimately approved by the Commission may result in an irrigation class revenue requirement that is different than that established in this case. The Commission will decide at that time whether it is necessary or appropriate to further modify irrigation class revenue requirement.

Q. Why didn't Staff support using the BPA credits or an alternative spread of power supply cost recovery among the classes to fully mitigate the rate increase?

A. BPA credits, as required by BPA rules, must go only to qualifying customers. Therefore, the credit may not be used to offset rate increases in other customer classes. With respect to recovery of extraordinary power supply costs, Staff believed that these costs were incurred based on energy consumption and should be recovered based on energy consumption. Any shifting of responsibility for cost recovery from one class to another would be inappropriate.

Q. After all of the revenue components are added, what is the revenue requirement for each customer class and how does it compare to the revenue requirement in 2001?

A. Staff Exhibit No. 103 shows the various revenue components for each class and compares the revenue requirement agreed to under the stipulation to last year’s revenue requirement.

RATE DESIGN

Q. What rate structure is recommended for the various customer classes under the Stipulation?

A. The parties to the Stipulation agreed that rate structure should remain unchanged for all classes except the irrigation class. The proposal is to reflect the change in revenue requirement for each class by modifying the energy component of the rate either up or down as necessary. Increasing the energy component was determined by the parties to be most appropriate given the nature of the extraordinary power supply costs subject to recovery. These variable costs were incurred based on energy consumption and are equitably recovered based on energy consumption. BPA credits are already provided on the basis of energy consumption and the rate mitigation component had to be applied based on energy consumption to be effective. Staff Exhibit No. 104 shows the new energy rates recommended for the Residential, General service and irrigation classes and a provides a comparison to rates in 2001.

Q. What is recommended for the irrigation class?

A. The parties agreed to eliminate the separate A, B and C firm and interruptible schedules in favor of a single firm rate. The parties also agreed to modify the energy rate component from a two block, declining rate to a three block, declining rate.

Q. Why was the interruptible rate eliminated for irrigators?

A. Most of the irrigation customers currently take service under Schedule C because it is the lowest price of the three service schedules available. Therefore these customers generate most of the revenue in the class. However, irrigators indicated that significant economic hardship was suffered in 2001 due to the numerous interruptions that occurred. Consequently, the Company and the parties agreed that a single non-interruptible rate at a price previously offered for interruptible service should be provided.

Q. Will irrigators be able to obtain further rate discounts for interruptible service?

A. Some of the larger irrigation customers on a case-by-case basis may be able to take interruptible service for a discounted rate. The Company agreed to discuss this type of service with irrigators that use energy at levels not subject to the BPA credit.

Q. Why was the energy rate changed from a two-tiered structure to a three-tiered structure?

A. The rate structure was modified to recognize that the BPA credit is applied to a limited amount of energy consumed during a given month. Establishing a third block at a lower price will help to mitigate rate impacts that will occur for usage not eligible for a BPA credit.

Q. Does that conclude your direct testimony in this proceeding?

A. Yes, it does.