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

A. My name is Terri Carlock. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as the Accounting Section Supervisor.

Q. Please outline your educational background and experience.

A. I graduated from Boise State University in May 1980, with a B.B.A. Degree in Accounting and in Finance. I have attended various regulatory, accounting, rate of return, economics, finance and ratings programs. I chaired the National Association of Regulatory Utilities Commissioners (NARUC) Staff Subcommittee on Economics and Finance for over 3 years. Under this subcommittee, I also chaired the Ad Hoc Committee on Diversification. Since joining the Commission Staff in May 1980, I have participated in audits, performed financial analysis on various companies and have presented testimony before this Commission on numerous occasions.

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

A. The purpose of my testimony is to address the issues identified in Order No. 28722, IPC-E-01-7 and IPC-E-01-11 for Idaho Power Company (Idaho Power, Company). These issues are trading practices (to include hedging, transmission and wheeling charges, Mid-C pricing and the use of weighted average pricing) and what has been termed the November trading event. All of these issues pertain to Case No. IPC-E-01-7 and IPC-E-01-11. The trading practices going forward pertain to Case No. IPC-E-01-16.

In initiating the present investigation regarding the $51.235 million of disputed power purchases, the Commission intended to investigate the Company's "trading practices (to include hedging, transmission and wheeling charges, Mid-C pricing, and the use of weighted average pricing)". Order No. 28722 at 17. In the prefiled direct testimony of several of its witnesses, the Company asserts that Staff's challenge to the Company's trading practices in the 2000-2001 PCA year is contrary to prior Commission Orders. The Staff does not agree with some of the characterization or inferences drawn from these interpretations of prior Commission Orders.

In particular, the Company maintains that the hedging and use of the Mid-C Price Index for day-ahead and real-time purchases were "previously reviewed and agreed to between Idaho Power and Staff and formally approved by the Commission in Order No. 28596 in Case No. IPC-E-00-13." Idaho Power Response to Comments at p. 8. As discussed later in more detail, Staff disagrees with Idaho Power's characterization that the Price Index Mechanism is not subject to review.

Staff recommends the assignment to the non-operating entity and therefore no recovery from Idaho customers of both the November transaction amount of $7,976,701 and the excess transfer pricing for power of $51,234,902 (Idaho jurisdictional numbers). These adjustments follow normal regulatory practices intended to protect customers from potential affiliate abuse. Staff further recommends Idaho Power establish and implement additional objectives and safeguards prior to acceptance of the Index pricing mechanism in future Power Cost Adjustment cases.

POWER COST ADJUSTMENT OVERVIEW AND HISTORY OF TRADING PRACTICES

Q. Please provide an overview of the Power Cost Adjustment (PCA) mechanism.

A. The PCA is a regulatory mechanism that allows for annual recovery or rebate of 90 percent of power costs differing from those already included in rates. The PCA rate adjustment has two components. First, power cost differences are projected each spring based on known snowpack. Second, differences between the projection and actual costs are tracked and trued-up in the following year. Inaccuracies in the projection can cause large after-the-fact true-up adjustments. Actual power costs come from the Company’s books and are verified by Staff audit each spring. By its nature, the mechanism allows for deferral of the costs and recovery after the fact. The majority of the audit verification takes place with the true up portion after the fact. Once the audit is complete, the Commission determines the amount of the deferral to authorize for recovery.

Q. Has the PCA mechanism changed since it was first implemented in 1993?

A. Although the basic PCA framework remains essentially the same, the PCA has evolved and changed over the years. Several of these changes are discussed in Company witness Greg Said’s prefiled direct testimony at pages 9 – 16.

When Idaho Power entered the speculative commodity trading business for non-system purposes in 1996, the accounting and reporting was not sufficient to adequately separate trades between system and non-system purposes. In Staff comments dated May 7, 1999, Case No. IPC-E-99-3 (Staff Exhibit No. 108, p. 3), Staff specifically addressed its concern with the Company's inability to accurately make this separation. Staff continued to express its concerns in the IPC-E-01-7 and IPC-E-01-11 Staff comments dated April 16, 2001.

Each year since 1996 when non-system trading activities began, Idaho Power made some changes to the way the separations were made. These changes were often made during the PCA year. Staff reviewed the changes after the fact and accepted them or made recommendations for further changes. Most of this process occurred between the Staff and Company during the audit. Other interested parties also participated at times. Changes were also made by Idaho Power to the pricing mechanism used to make the separations. These changes were not prospective but reviewed as part of the PCA. The prudence of all transactions was always reviewed after the fact during the true up phase of the PCA. Staff reviewed the transactions based on the information available at the time that the decision was made.

Q. Staff made an adjustment for approximately $51 million associated with the transfer price from the non-system operation to the regulated system. Please explain why.

A. The market price is not reflective of a reasonable price surrogate between the system and non-system for the intra-month purchases. The transfer price between affiliates must be shown to be reasonable.

To compensate for this change, Staff proposes to modify the pricing mechanism for the 2000 – 2001 PCA year for intra-month to more accurately reflect the total cost. The non-system purchases were less costly overall than the system purchases at market index. Since these transactions are with a speculative arm of IDACORP (regardless of whether IES was a part of Idaho Power or a separate subsidiary dealing with Idaho Power), Idaho Power must show the continued reasonableness of the transfer prices. The lower-of-cost or market for purchases and the higher-of-cost or market for sales is the standard default pricing mechanism used for regulated entities when a proper pricing mechanism between affiliates entities has not been justified.

Enhanced audit steps are performed to review affiliate transactions and to protect customers from possible affiliate manipulation. In connection with the stipulation made in Case No. IPC-E-00-13 and reflected in Order No. 28596, it was clear that continued review of the pricing mechanism would occur. This assurance was provided to address the concerns of parties in the case related to the affiliate contract and contract pricing.

Q. Please compare system and non-system term transactions.

A. Term transactions were implemented for non-system purposes but effectively stopped for system purposes after September 2000. Staff is concerned that Idaho Power has substantially limited long-term power contracts (i.e., in excess of one month) for the system-operating book. Confidential Staff Exhibit No. 109 shows the actual system purchases. This exhibit shows no term purchases for January and February 2001 as shown in Columns 3 and 4. Long-term purchases entered prior to the IES contract, account for minor term purchases for the system in Columns 5 and 6. Confidential Staff Exhibit No. 110 shows the actual non-system purchases of approximately 80% for January and February 2001. Confidential Staff Exhibit Nos.

111 and 112 reflect the sales transactions. All Exhibit Nos. 109 through 112 show graphs to reflect the day ahead, real time, term and total transactions for the 2000 – 2001 PCA year.

The ability to purchase power at a fixed price is a valuable tool for rate stability. In the past, the Company has purchased large amounts of power at relatively inexpensive prices to serve its load. This is a change in activity and operations that was not expected. On the contrary, the parties were assured during the Company's workshops that the operations would not change.

Q. Isn't it reasonable to expect non-system transactions to differ from system transactions due to the increased level of risk the non-system may be willing to bear?

A. Yes, the magnitude of the transactions would differ. The non-system may execute additional and potentially more risky deals. However, the direction and the existence of transactions should be consistent. Therefore, since the non-system executed term transactions, the system should have had some corresponding transactions within its risk bands.

Term transactions reduce the price variability and usually the cost for that time period.

Since the term transactions were effectively stopped for the system, the cost to customers was higher. The power purchases were shifted to intra-month and priced at the market index.

Q. Please describe the background events leading to the Company's current trading practices?

A. Company witness Sharon Hoyd outlines the development of wholesale power markets following FERC's issuance of Order Nos. 888 and 889 in 1996. As she explains in her prefiled direct testimony at pages 3 – 11, while the development of markets and the use of various market devices such as futures and options increased, the accounting industry was also developing more stringent accounting rules. The purpose of these new accounting rules was to appropriately separate the buying and selling of energy for utility operation from the buying and selling of energy for trading or speculative purposes. Eventually, the Financial Accounting Standards Board (FASB) and its Emerging Issues Task Force (EITF) promulgated Generally Accepted Accounting Principles (GAAP) for these transactions. The adoption of accounting standards resulted in the issuance of Statement of Financial Accounting Standards (SFAS) 133, SFAS 138, and EITF 98-10.

Q. What do these standards require?

A. I agree with Ms. Hoyd's explanation that:

> EITF 98-10 was written to give clarification between energy contracts and energy <u>trading</u> contracts for accounting purposes. SFAS 133 and SFAS 138 were written to ensure that all obligations with market price exposure are reflected in the financial statements.

Hoyd Prefiled Direct Testimony at 7, ll. 7-11 (emphasis added).

Q. Did the Company and Staff discuss the adoption and application of these new accounting standards to Idaho Power?

A. Yes. In a letter dated March 18, 1999 to the then administrator of the Staff's Utility Division, Company witness Ric Gale stated that the Company was changing its classification and reporting of purchase and sales transactions relating to its power trading operations. Staff Exhibit No. 113 at p. 1. In particular, transactions (including purchases and sales) pertaining to "the balancing of the [Company's] system load and . . . system reliability are classified as 'system' [transactions]." *Id.* Conversely, transactions not related to the balancing of the system load and resources are classified as "non-system" transactions. *Id.* Idaho Power requested that the administrator provide a “letter indicating the Commission’s acknowledgement of these changes.” *Id.*

Q. Did the administrator forward a letter to the Company?

A. Yes. In a April 7, 1999 letter to Mr. Gale, Stephanie Miller (the Utilities Division Administrator) noted that the Commission understands the Company’s implementation of the system and non-system accounting. Idaho Power Exhibit No. 9. Her letter stated that the Commission “does not take exception to the described accounting changes but reserves judgment on ratemaking issues related to the exclusions of these [non-system, marked-to-market] transactions from the PCA.” *Id.*

Q. What was the next historical event?

A. As a result of implementing the accounting changes, the Company in the 1999-2000 PCA case (Case No. IPC-E-99-3) separated power transactions for the months of January, February, and March 1999 into operating and non-operating transactions. Idaho Power Exhibit No. 7, Order No. 28049 at 2. The Order further recites that the Staff asserted in its comments that “it is unable to reach any firm conclusions about future effects of removing the non-operating power marketing transactions from the PCA." *Id.* at 3.

In that PCA case, the Industrial Customers of Idaho Power (ICIP) also expressed concern that removal of the non-operating sales from the PCA would remove the revenue accruing to ratepayers from such sales. *Id.* "The ICIP is concerned that Idaho Power's management has every incentive to maximize the amount of sales removed from the PCA while minimizing the amount of expenses removed." *Id.*

Likewise, FMC (now Astaris) expressed similar concerns. In particular, the Order recites that FMC insisted that "ratepayers are entitled to assurances that costs are properly allocated to the Company's competitive activities and the ratepayers are compensated for any use of utility resources to support the speculative trading." Idaho Power Exhibit No. 7, Order No. 28049 at 4.

The Commission agreed with FMC and ICIP that:

> Adequate safeguards must be in place to ensure that the Company's ratepayers are protected from the risks associated with such [speculative trading] activities. We believe that it is premature to conduct a formal hearing relating to this issue but agree that further consideration of this issue is

> warranted. We direct the Commission Staff to coordinate with Idaho Power, FMC, the ICIP and all other interested persons to determine, informally, how best to address the issue. Those parties might consider conducting a workshop. If necessary, any or all of them are free to petition this Commission to initiate a formal case. Regardless, we expect that some written work product will ultimately emanate from the efforts of the parties containing an analysis of the issue and a recommendation regarding what action, if any, is needed by this Commission.

Idaho Power Exhibit No. 7, Order No. 28049 at 5.

Q. Following the issuance of this Order on May 14, 1999, did the parties participate in a workshop?

A. Yes. As verified by Company witness Said on page 14 of his prefiled direct testimony, a workshop was held on September 23, 1999.

Q. Did the workshop result in a “written work product”?

A. Yes. Staff Exhibit No. 114 reflects the memorandum dated February 14, 2000 the Staff submitted a two-page memorandum with four attachments representing written materials filed by Idaho Power, the Commission Staff, ICIP, and Astaris. Staff’s written report labeled as Attachment D (Staff Exhibit No. 114, pgs. 51 - 56), noted that Staff examined the off-system transactions for <u>only</u> the month of August 1999 “and finds the adjusted Mid-C average daily price to be an acceptable price to use for these inter-book transfers. . . . The Staff concluded that the Mid-C price with the transmission adjustment is a fair and just pricing mechanism to use for the inter-book transfer [between operating and non-operating books of Idaho Power].” Staff Exhibit No. 114, p. 51.

The Staff Report also noted that Idaho Power customers “are not necessarily benefiting from the relationship shared with the energy trading activities.” *Id.* Prior to the end of revenue sharing on December 31, 1999, customers shared the risks and any benefits from the energy trading contracts. Staff concluded that new discussions between the parties needed to be held to discuss risk, rewards, and allocations in basic rates.

Q. Was the Staff memorandum dated February 14, 2001 submitted into the 1999-2000 PCA case record?

A. No, however, in Order No. 28358 issued May 9, 2000, the Commission acknowledged that the Staff Report was previously filed with the Commission. However, the mention of the Staff Report addressed only ICIP’s recommendation that the Commission initiate a new proceeding “to consider changes to rate structure for Idaho Power." Staff Exhibit No. 115, Order No. 28358 at 5.

Q. Did the 1999-2000 PCA Order No. 28358 (Case No. IPC-E-00-6) address hedging or the use of the Mid-C Price Index?

A. No. For this reason, the Commission should not infer from Greg Said's prefiled direct testimony at page 15, lines 6 - 16, that the Commission did so. The Commission "acknowledged the Staff memorandum addressing the accounting change concerns raised by opposing parties." But as he indicates in the next sentence, the accounting change alluded to by the Commission Order No. 28358 concerns the separation of "energy contracts" (i.e., operating transactions) from "energy trading contracts" (i.e., non-operating transactions).

Q. What happened next?

A. IDACORP created the IDACORP Energy Solutions affiliate (IES) to be responsible for natural gas commodity trading. IDACORP expanded the IES duties to include the wholesale power market purchases and sales for Idaho Power. To formalize the relationship between the non-regulated affiliate (IES) and the regulated utility (Idaho Power), the Company filed an application on September 1, 2000 requesting approval of a proposed Electric Supply Management Service Agreement ("the Agreement") between Idaho Power and IES. This was assigned Case No. IPC-E-00-13.

Q. In their prefiled direct testimonies Company witnesses Said and Gale imply that Commission Order No. 28596 in Case No. IPC-E-00-13 authorized the Company to utilize Mid-C Price Index for real-time and day-ahead transactions. Staff Exhibit No. 116, Order No. 28596. Do you concur with these assessments?

A. No, I believe the Company's reliance upon this Order is premature for several reasons. First, in the IPC-E-00-13 case, Idaho Power filed an application requesting approval of the proposed Agreement between Idaho Power and its unregulated affiliate, IES. Staff Exhibit No. 117. What the Staff and Company do agree upon is that Order No. 28596 approved the adoption of the proposed Agreement. Where the Company and Staff disagree is the effect of the adoption.

It is Staff's contention that by its explicit terms the Agreement and its Statement of Services (including use of the Mid-C Price Index in ¶ 5.1 of the Statement of Services) were not effective.

Staff Exhibit No. 117 at p. 7. However, paragraph 9 of the Agreement provides

> 9. Commission Approval. This Agreement and any future amendments shall not become effective until the Commissions have issued their respective final orders approving the agreement or any future amendments. If the final orders of any of the Commissions initially approving this agreement contain material terms or conditions that either party finds unacceptable, within fourteen (14) days of the issuance of the order, the adversely affected party will have the right to cancel this agreement by giving thirty (30) days written notice of cancellation to the other party.

Staff Exhibit No. 117 p. 7 (Agreement ¶ 9 at p. 4) (emphasis added). The term "Commissions" specifically include the Idaho Public Utilities Commission, the Oregon Public Utilities Commission, and the Federal Energy Regulatory Commission. Staff Exhibit No. 117 at ¶ 6 p. 7. Given the explicit terms of the Agreement, it is Staff's position that its operating terms, including the use of the Mid-C pricing mechanism, were not effective at the time this Commission issued its Order No. 28596 approving the Agreement on December 19, 2000.

Q. When did the Agreement become effective?

A. By its own terms, the Agreement did not become effective until the Oregon PUC and FERC approved the Agreement. FERC conditionally approved the Agreement effective April 28, 2001. See Exhibit No. 118 (95 FERC ¶ 61,147 (2001)). FERC did not approve the Agreement as initially submitted. Instead, FERC required the Agreement to be modified to reflect that the Mid-C Price Index not be used for real-time transactions. Staff Exhibit No. 118 at pp. 1-2. On May 14, 2001, Idaho Power and IES filed the requisite change to its pricing of real-time transactions. Staff Exhibit No. 119.

Q. When did the Oregon Commission approve the Agreement?

A. The Oregon PUC did not issue its approval until July 3, 2001. Staff Exhibit No. 120. Thus, under the terms of the Agreement, it was not effective until July 3, 2001 -- well after the end of the 2000-2001 PCA year.

Q. Has the Company submitted the FERC required change to the Agreement for this Commission's approval?

A. As of July 20, 2001, the Company had not filed an application requesting that the Idaho

Commission approve the FERC required amendments to the Agreement.

The Pricing Mechanism and Disputed $51 Million

Q. Did the Company provide any rationale for why it utilized the pricing mechanism contained in the Agreement even though the Agreement was not effective?

A. In Company witness Gale’s direct prefiled testimony in the combined IPC-E-01-7 and IPC-E-01-11 cases, he was asked a question about when the Company implemented any of the pricing mechanisms included in the Agreement. He replied:

> Yes, the Company adopted the transfer price for real-time hourly transactions once the IPUC approved the Electric Supply Management Agreement. This change was implemented not because the Agreement had become effective, but because once the Agreement and the transfer pricing were approved by the IPUC, the Company viewed the new real-time transfer price as the appropriate price.

Prefiled Direct Testimony Gale at p. 6, ll. 10-16.

Q. Was the Company’s use of the Mid-C Index effective on a going forward basis as of the date of the IPC-E-00-13 Order, December 19, 2000?

A. No. Mr. Gale indicates that the Company made the change to real-time hourly pricing in December 2000. However, Company witness Hoyd testified the Mid-C pricing methodology was used to calculate its power purchase cost from April 2000 for the PCA calculation. Hoyd Prefiled Direct Testimony at 21, ll. 5-9.

Q. Idaho Power states that the market pricing mechanism it used was approved in Order No. 28596, Case No. IPC-E-00-13. Why should that be changed for the 2000-2001 PCA year?

A. As previously stated, the allocations, separations and pricing mechanisms used in the PCA over the years has evolved. These changes may have been for part of a PCA year or for the full PCA year. Each year the prior year mechanism was reviewed for reasonableness in the true-up audit.

The Staff audit function and the Company's requirement to demonstrate the continued reasonableness of market pricing was the safeguard proposed and adopted by parties as part of the workshops and stipulation in IPC-E-00-13. Even with this safeguard, the Industrial Customers of Idaho Power remained uncomfortable with the mechanism and did not sign the stipulation. It would not have been acceptable to Staff and other parties to endorse a 5-year contract between the parties without the burden remaining on the Company to show the continued reasonableness of the Mid-C Index as a surrogate for price.

The simple fact is that even if the Agreement had been in effect, the Company did not comply with the agreed upon documentation, oversight manager, and audit tracking mechanisms safeguards necessary to justify the reasonableness of its market-priced transactions.

Q. Was the retention of documentation of marketing transactions and decision-making a concern?

A. Yes. The lack of documentation retained by Idaho Power to support the decisions was a concern expressed during the audits since 1997, in Staff comments and during subsequent workshops. This lack of retained documentation continues to be a concern in this case.

The documentation concern now pertains to the pricing mechanism in addition to the assignment/allocation of transactions between system and non-system. Approval of the pricing mechanism in Case No. IPC-E-00-13 was prefaced on the continued review and ongoing improvements to the process. This is no different than the process that had always been followed between the Staff and Idaho Power for the PCA review. In the instant cases, IPC-E-01-7 and IPC-E-01-11, the dollar magnitude is greater. The increase in this magnitude is partially due simply to the increase in transactions entered into by Idaho Power and now its affiliate IDACORP Energy. Any time transactions occur between affiliates, the necessary review and documentation required for separations, allocations or the pricing products are enhanced. Failure to require enhanced scrutiny of affiliate transactions could allow increased costs to be charged customers by manipulation of the affiliate relationship.

When Staff conducted its true-up audit of Company transactions made during the 2000-2001 PCA year, it discovered pricing concerns related to the ongoing reasonableness of using the Index pricing as a surrogate. These concerns must be corrected by allocating the higher transfer prices to the non-regulated operations. To this end, Staff recommends non-recovery of the $51,234,902 (Idaho jurisdictional amount).

Proper safeguards must be implemented to address and eliminate these issues in the future.

Once objectives and safeguards are approved and in place, future true-up audits for prudence will focus on compliance with these objectives and safeguards.

Q. Are there other reasons why the Commission should adopt the Staff’s adjustment to power costs rather than using of the Mid-C Price Index?

A. Yes. Restricted to its context in the Case No. IPC-E-00-13, the Staff and the Company suggested that use of published market indices is an appropriate method for pricing transactions between regulated and non-regulated affiliates. However, IES was not licensed by FERC to conduct trading activities until it received FERC approval on April 27, 2001. See Staff Exhibit No. 118. The trading was performed under Idaho Power’s authority. The point here is that until the Commissions and FERC approved the Agreement between IES and Idaho Power, all power purchases were made by Idaho Power not IES. Because Idaho Power was purchasing energy for itself, ratepayers should not pay a price for that power that is significantly higher than its cost, even if the “price” was the market index.

Idaho Power was asked in audit requests to supply vouchers, invoices or documentation supporting compliance with the terms of the contract. The

Company responded that the contract was not in effect since it lacked the required approvals. Consequently, the Company insisted the other provisions had not yet taken effect. The other provisions -- $2 million annual credit, Idaho Power Oversight manager, implementation of audit tracking mechanisms -- were safeguards to insulate customers from potential affiliate abuse.

Even though the Company utilized the pricing mechanisms contained in the Agreement, the Company did not credit Idaho retail customers with the stipulated $2 million. Direct Testimony of witness Gale, Case Nos IPC-E-01-7 and IPC-E-01-11 testimony at p. 4, ll. 6 - 9.) John R. Gale, Vice-President of Regulatory Affairs, notified the Commission in a letter dated June 29, 2001 that the “commitment to initiate the flowback obligation” of $2 million annually, would go into effect on July 1, 2001. Staff Exhibit No. 121. Consequently, the pricing mechanism should go into effect no sooner than that date.

Q. Is it possible for a pricing mechanism to be reasonable at one point in time but not at another time period?

A. Yes. As markets change and the relationship between affiliated interests change, it is possible for a pricing mechanism to be reasonable at one point in time but not at another. The magnitude of transactions also impacts the possibility that the reasonableness may change. When the level of market participation and the dollar prices are small, the transactions' reasonableness is more likely to fall within an acceptable band. As the transactions change, the level of activity and the price increase. This exacerbates the differences between a surrogate or market price and the actual cost of the affiliate beyond an acceptable band, making it so the market price is no longer reasonable.

Q. Please explain the calculation for the pricing adjustment recommended by Staff.

A. For the months of December 2000, January 2001 and February 2001, Staff has re-priced the day-ahead power purchased from the Non-Operating System to the System at the daily weighted average price paid by the Non-Operating System. That way, the System pays exactly what the Non-Operating System pays. The Non-Operating System should not be allowed to profit substantially from the regulated system. Staff believes that the weighted average price is fair and reasonable. It provides incentive to make sure that all trades are sound and reasonable for both the system and non-system transactions with minimal ability to game or manipulate the price. Substantially greater margins on similar transactions for a non-regulated entity compared to a regulated entity is an indicator of an improper pricing mechanism. The magnitude of this adjustment is shown on Staff Confidential Exhibit Nos. 122 - 127. Staff Confidential Exhibit No. 122 shows the daily record for December 2000, Staff Confidential Exhibit No. 123 shows the daily record for January 2001, and Staff Confidential Exhibit No. 124 shows the daily record for February 2001.

Consistent with the adjustment for the detailed audit for the three months listed above, Staff determined that the rest of the day ahead power for the PCA year should be re-priced using a weighted average monthly price. While not as precise as a daily price, Staff believes it is fairly representative. These months were not audited on a day by day basis due to time constraints. The months of August and September 2000 did not have adjustments, the transfer prices were already at the lower of cost or market, when compared to the weighted average monthly price for purchases, and at the higher of cost or market for sales. This adjustment is shown on

Staff Confidential Exhibit No. 125 for the months of April through November 2000.

Staff has made adjustments to the day ahead transactions for the months of April 2000 through February 2001, with the exception of the months of August and September, and included them in the Non-Firm Purchases and Surplus Sales, Lines 19 and 20 of the PCA calculation on Company Exhibits 1 and 3 of Case Nos. IPC-E-01-07 and IPC –E-01-11, respectively. The net adjustment, before the jurisdictional and sharing allocations, and without the effect of interest on the deferral balance for the day ahead transactions is ($61,467,386.84). The Idaho jurisdictional number is $51,234,902. This represents a benefit to the customer. The calculation is summarized on Staff Exhibit No. 128.

In December 2000, the Company changed the way the Real Time Transactions were priced. In the past, the transactions always flowed through the system at their actual cost. Now, however, the transactions are priced based on the weighted average price of all real time transactions that touch the Idaho Power system on an hourly basis. According to Staff’s analysis, this has also resulted in overcharges and underpayments in several cases. Staff has re-priced the real time purchase transactions for the months of December 2000 through February 2001 to the lower of the Non System's cost or market price. Staff has also re-priced the real time sale transactions for the same months using the higher of sales price or market. Staff believes that purchases and sales should be kept separate and that the system should get the benefit of the best price.

The Staff made adjustments to the inter-book real time sales and purchases for the months of December 2000, and January and February 2001. The net adjustment, before the jurisdictional and sharing allocations, and without the effect of interest on the deferral balance, for the real time transactions are ($4,666,381.95). This represents a benefit to the customer. The calculation is shown on Staff Confidential Exhibit Nos. 122 - 125 and summarized on Staff Exhibit No. 128.

NOVEMBER TRANSACTION

Q. Please explain what has been termed the 'November transaction'.

A. The 'November transaction' is the transaction identified by Staff during the PCA audit as an adjustment in the true up. The Risk Management Committee (RMC) Minutes reflected a term transaction for the system that was not completed. Staff adjusted the PCA results as if that transaction were completed resulting in a recommended removal of the higher priced replacement power from the recommended increase. Idaho Power claims the transaction was not completed because the RMC changed its decision later during the same meeting. The continued Staff review of this transaction and the explanation by Idaho Power does not change the Staff position.

Q. Please explain the operating plan.

A. The operating plan is a primary planning tool used by Idaho Power to operate the system and is a primary tool used by the RMC for its decision making related to the system. The operating plans are the documents provided to Staff to support the power purchase transactions, sales transactions and the decisions made by the RMC. The operating plans show the forecasts under the expected scenario, a best scenario and a worst scenario.

Q. What did the operating plans reveal that are available for the time of the RMC meeting on November 21, 2000 when the purchase decision was made for January?

A. The operating plans provided to Staff showed that under almost every scenario the system would be short in January. The RMC minutes and available supporting documentation do not provide information to counter the original decision to purchase power for the system to cover the January shortage. Any subsequent information on pricing or other data was not reflected in the RMC minutes or retained to support the decisions made. Absent this documentation, the change of decision simply looks like a bad decision or an error that was contrary to the prudent decision originally made, and passes the detrimental cost to customers. These costs should not be recovered from customers. The decision not to purchase was made by the RMC and should be absorbed by the non-system operations.

Staff has adjusted the amount of the purchased power expenses in January 2001 by the total system amount of $10,288,386, as shown on Staff Confidential Exhibit No. 127, that would have been saved if the RMC had completed the directive. All the documentation supports a forward purchase of power for the system. Rationale for a change of vote has not been provided. It is reasonable for Staff to adjust the purchase power expense to reflect the purchase as if it had been made. To do otherwise would pass the result of improper decision on to customers at their expense.

Q. Why does Staff find the Company’s explanation unpersuasive?

A. The operating reports available for review, the RMC minutes, and the subsequent events referenced by Idaho Power do not justify the reversal of this term transaction. The subsequent events do not reflect the same product for comparison. A longer-term product may be packaged to get a better deal overall even when one portion of the transaction would result in an imbalance for the system. Idaho Power could have been short in January but still packaged a deal that would sell power for the first quarter in exchange for power in the third quarter. These transactions are not mutually exclusive.

Q. In his testimony Darrel Anderson, Vice President – Finance & Treasurer, Idaho Power Company, explains why the system didn’t need to purchase for January 2001. Do you accept his explanation as a protrayal of the complete facts?

A. No. Price trends from Idaho Power documents also reflect forward prices for January 2001 increasing. While there may be several reasons for any increase, historical price trends were probably not the primary consideration. Recent price increases for gas and electricity caused decisions by most traders to be based on other data, such as forward market prices, total trading position of IDACORP and Idaho Power. Staff Confidential Exhibit No. 129 summarizes the operating plan forecasts and the forward market price data available as documentation for RMC decisions. The November transactions relates to the November 21, 2000 RMC meeting. The documentation retained includes the operating plans for November 16, 2000 and November 28, 2001 but not anything in between.

Exhibit No. 129 shows the operating plan documentation to sketch the transaction referred to by Company witness Anderson for the forward sale of power in the First Quarter of 2001 in exchange for the purchase of power in the Third Quarter of 2001. If market prices were higher in the third quarter than the first quarter, Mr. Anderson’s claim that they wouldn’t sell if short might not be completely accurate because line 24 of Staff Exhibit No. 129 shows they completed the opposite where they were buying for the third quarter when September was forecasted to be long. This exhibit shows how forward market prices and inventory may have been greater factors for consideration than absolute balance of the system forecasted need.

Q. Please explain how these problems can be avoided in the future.

A. Proper documentation to support prudent decisions should include information supporting the decision or change in decisions and the rationale if the decision made is not directly supported by the available data. All charts or discussion papers must be retained as support. The PCA review is conducted at least annually. This is a reasonable time frame for the Company to retain such documentation. If the decision can not be shown to be prudent at the time it was made, the associated expenses should not be recovered from the regulated customer but should be assigned to the non-system operation or recorded below the line.

REQUIRED OBJECTIVES AND SAFEGUARDS

Q. Please provide an overview of the objectives you believe Idaho Power must implement related to trading activities and risk management.

A. Idaho Power is responsible for providing power at a reasonable cost to its customers. To assure the costs are reasonable, Idaho Power must maintain documentation and RMC minutes reflecting the data available and considered in making its decisions. When a product or service is provided to the regulated utility from an affiliate or non-regulated operation, the review by the Commission Staff of those transactions must be enhanced. Therefore Idaho Power must retain and provide additional documentation above that required for a third-party transaction.

The objectives I recommend the Idaho Power focus on include the following categories: 1) term transaction decision management and documentation, 2) forecasting documentation, 3) risk management profile measures, 4) performance standards and 5) transfer of value evaluations. These objectives, as further discussed by Staff witness Thomas J. Lord, will provide parties to Idaho Power cases additional opportunity to review the decision making process of Idaho Power and ensure that customers are paying reasonable prices for power. The affiliate relationship and the transfer pricing mechanisms are a major portion of the review conducted by Staff and parties to assure the transfer prices are and remain reasonable.

Q. Would you anticipate that the lower-of-cost or market for purchases and the higher-of-cost or market for sales continue now that IDACORP Energy is in full operation and in separate facilities from Idaho Power?

A. I believe market pricing for the intra-month transactions will be the appropriate pricing mechanism once the control objectives are quantified and operational. Staff recommends for the current filings, IPC-E-01-7 and IPC-E-01-11 that the following pricing mechanisms apply to all day ahead transactions:

1. Purchases by Idaho Power from the non-operating book for the system should be priced at the lower of cost or market. Staff recommends that the market price continue to be based on the Mid-C price or another acceptable pricing mechanism approved by the Commission.

Staff further recommends that the cost be based on the actual cost of the power, using a daily weighted average of the price actually paid for the power by the non-operating book to third parties.

2. Sales from Idaho Power from the operating book to the non-operating book should be priced at the higher of cost or market. Staff recommends that the market price continue to be based on the Mid-C price or another acceptable pricing mechanism approved by the Commission.

Staff further recommends that the cost be based on the actual price of power sold to third parties.

These pricing recommendations will provide the ratepayer with the assurance that they will not pay rates based on prices that are unfair, unjust and unreasonable.

The Company, Staff and other interested parties should work together to develop the objectives and safeguards. This is critical to ensure the reasonableness of using an Index as a surrogate for actual costs going forward in IPC-E-01-16. The continued cooperative efforts are necessary to achieve a workable solution. Idaho Power has informally indicated they favor the proposed process. The resulting objectives and safeguards should be presented to the Commission for approval or rejection in the order issued in Case No. IPC-E-01-16. These efforts will be made between now and the hearing in these cases.

Absent appropriate safeguards, Staff will continue to propose lower-of-cost or market for purchases and the higher-of-cost or market for sales as the only transfer pricing mechanism to assure there in no affiliate manipulation and that customers are charged fair, just and reasonable rates.

RISK MANAGEMENT COMMITTEE

Q. Please provide an overview of the Risk Management Committee?

A. During the 2000 – 2001 PCA year, the Risk Management Committee (RMC) consisted of IDACORP and Idaho Power officers. These members are listed on Exhibit No. 130 as provided in Response to Staff Production Request No. 1. No member solely represented the interests of Idaho Power and its customers.

According to Idaho Power, "The purpose of the RMC is to maintain general oversight over all commodity trading and financial risk management operations." Response to Staff Production Request No. 3. The decision-making process of the RMC is explained in Response to Production Request No. 4.

> The RMC reviews operating proposals prepared by Idaho Power Company personnel. The proposals include assumptions for supply and demand requirements based on data available at that time. Based on the results of this data, the collective experience of the committee members, other pertinent internal and external data, and an in-depth discussion between committee members, decisions are made to determine the need to buy or sell energy. Numerous factors are considered in coming to these decisions including weather, expected

> load requirements, current snowpack, transmission availability, pricing and the overall system portfolio position. When it is determined that an action is required, a recommendation is made by a committee member and put to the entire RMC for a vote. A majority is required to confirm a transaction for inclusion in the operating plan.

Staff expressed concern in its comments filed on April 16, 2001 in these cases that the RMC consists of the same members for both the utility and for the non-regulated operations. Staff review of the RMC minutes indicates that the Committee does not consistently support a mandate to first take care of the system needs **before** the non-regulated operations, even though this is the stated policy. Based on a review of the minutes, Staff believes that the RMC has not focused enough energy on the utility and as a result, system costs are higher than they otherwise would have been.

Recently the Risk Management Committee was split into two committees, an IDACORP Energy Risk Management Committee and an Idaho Power Risk Management Committee. The current members of the committees are listed on Exhibit No. 131. This split should allow the respective committees to focus more directly on its primary responsibilities. The non-operating group, now IDACORP Energy can focus on non-regulated matters and the Idaho Power RMC can focus on matters pertaining to the regulated operations.

Q. Does this conclude your direct testimony in these cases?

A. Yes, it does.