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April 8, 2005

VIA EMAIL AND US MAIL

Filing Center
Oregon Public Utility Commission
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308-2148

Re: UE 167 - Rebuttal Testimony of Gregory W. Said, Dennis E. Peseau, Pete Pengilly, Keith J. Kolar, and John R. Gale On Behalf of Idaho Power Company

Dear Sir or Madam:

Enclosed for filing in the above-referenced docket is the original and five copies of Rebuttal Testimony of Gregory W. Said, Dennis E. Peseau, Pete Pengilly, Keith J. Kolar, and John R. Gale On Behalf of Idaho Power Company. Please contact me with any questions.

Very truly yours,

Jessica A. Centeno

Enclosures
cc: UE 167 Service List
Bart Kline

CERTIFICATE OF SERVICE
UE 167

I hereby certify that a true and correct copy of **REBUTTAL TESTIMONY OF GREGORY W. SAID, DENNIS E. PESEAU, PETE PENGILLY, KEITH J. KOLAR, AND JOHN R. GALE ON BEHALF OF IDAHO POWER** was served via U.S. Mail on the following parties on April 08, 2005:

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*Indicates parties who have signed the Protective Order. These parties will receive confidential versions of the above-referenced document(s). All other parties will receive redacted versions.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO CUSTOMERS IN THE	)
STATE OF OREGON	)
	)

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name and business address.

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same Gregory W. Said that presented direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I will explain why Staff's, CUB's, and Oregon Industrial Customers of Idaho Power ("OICIP")'s testimony regarding normalization of power supply expenses are unrealistic and inconsistent with the power supply expense normalization principles that this Commission and the Idaho Commission have followed to set electric retail rates for Idaho Power for over 20 years. I will demonstrate that projections of future net power supply expenses proposed by Staff, CUB, and OICIP cannot reasonably be expected to occur during the period of time rates will be in effect. As a result, if Staff, CUB, or OICIP recommendations for net power supply expenses are adopted by this Commission, Idaho Power will have no realistic opportunity to recover its reasonably incurred power supply expenses. I will also explain why the Commission should reject OICIP witness Dr. Reading's recommendation regarding rate basing of the Company's Danskin power plant in the same manner that the Idaho PUC rejected Dr. Reading's identical recommendations in Idaho.

NORMALIZED POWER SUPPLY EXPENSE

Q. What is the meaning of the word "normal" in statistics?

A. "Normal" refers to a distribution of values that has a specific shape commonly called a bell curve. The shape of the bell curve is symmetrical around a central value called the mean or mathematical average of the distribution.

Q. Are there other measures of central tendency in addition to the mean?

A. Yes. In addition to the mean, two additional measures of central tendency are the median and mode. The median of a distribution is the value within the distribution that is greater than half of the values within the distribution and is also less than half of the values within the distribution. The mode of a distribution is the most frequently occurring value within the distribution. For a normal distribution, the mean, median and mode values are the same. Most "real world" distributions are non-normal in that they do not fit the shape criteria and therefore have different mean, median and mode values.

Q. What is the meaning of the word "normalize" when referring to power supply expenses in a rate case?

A. When looking at the historical distribution of observed annual power supply expenses, it is readily apparent that the historical distribution does not fit the statistical definition of a normal distribution and has different mean, median and mode values. However, from a rate-making perspective, the Commission desires to determine a measure of central tendency or "normal" level of power supply expenses such that the amount allowed in rates is not perpetually higher than the amount of power supply expenses the Company actually experiences and, likewise, the amount allowed in rates is not perpetually lower than the amount the Company actually experiences.

Q. What is the method for normalizing Idaho Power's test year power supply expenses that has been utilized by this Commission and the Idaho Commission since 1982?

A. The method for normalizing Idaho Power's test year power supply expenses that has been utilized by the Oregon and Idaho Commissions since 1982 has been to first establish a representative distribution of annual power supply expenses and then use the mean value of the distribution as representative of the "normal" central tendency. The distribution of annual power supply expenses in this case consists of 76 observations (hydroelectric supply based upon water conditions 1928 through 2003) of the annual power supply expenses that would theoretically occur given 2003 test year loads (demand). The distribution is representative of what the Company would experience over time. Market prices for each scenario (water condition) are determined based upon economic principles, i.e. given fixed demands and variable supply, prices are higher during times of limited supply and prices are lower during times of abundant supply. The average of the 76 annual power supply expense determinations associated with each of the 76 water condition scenarios as the Company has presented in this case complies with the Commission approved methodology for determining normalized power supply expenses.

Q. Why did the Oregon and Idaho Commissions adopt this method of normalizing Idaho Power's power supply expenses?

A. Prior to 1982, both the Oregon and Idaho Commissions evaluated a single supply side scenario assuming a median water condition to determine power supply expenses for revenue requirement purposes. Under a median water scenario, the Company did not have any monthly deficiencies and therefore had no purchased power. However, drought experiences in the 1970's demonstrated that cost variations associated with drought conditions varied from median to a greater extent than cost variations associated with abundant water. Statistically, it was demonstrated that the average cost associated with multiple conditions was different and higher than the cost of a single average or median condition. In order to capture the full range of cost variability that could theoretically occur, both the Oregon and Idaho Commissions adopted the current power supply expense normalization method for Idaho Power.

Q. Staff witness Galbraith states that annual net power supply expenses that appear in the Company's modeling of 76 separate water conditions (i.e. water years 1928 through 2003) range from a high of $147.8 million to a low of –$7.1 million. How do these modeled extremes compare to the actual extremes in net power supply expenses that the Company has encountered?

A. In order to respond to this question, I had an exhibit prepared that provides the Company's actual net power supply expenses over the last 22 years, a period of time that includes both the highest and lowest water conditions on record. Exhibit Idaho Power/201 shows that the range of actual net power supply expenses over the last 22 years has been from a high of $279.5

million to a low of –$18.7 million. Actual net power supply expenses have exceeded the modeled high extreme of $147.8 million 3 times in recent history (2000, 2001 and 2003). Actual net power supply expenses have been below the modeled low extreme of –$7.1 million twice (1983 and 1984).

Q. Staff witness Galbraith states on page 2 of his testimony that "Idaho Power's projected annual NVPC shows an asymmetric distribution that is skewed towards high NVPC." Please comment on this testimony.

A. On numerous occasions in his testimony, Mr. Galbraith describes Idaho Power's process as "projecting" power supply expenses or "projecting" various components of power supply. I would like to clarify that Idaho Power is not projecting future actual net power supply expenses. Normalization is not a process that predicts future net power supply expenses, but rather is a process that considers the potential *variation* in future net power supply expenses. Likewise, power supply modeling includes analysis of potential variation in the various components of power supply such as hydroelectric generation, coal-fired generation, natural gas-fired generation and wholesale electricity prices. It is important to understand that the basis for the power supply normalization methodology that Idaho Power has utilized in Oregon and Idaho since 1982 has been to use the mean net power supply expenses derived from a distribution of modeled annual net power supply expenses corresponding to potential variation of future water conditions represented by historical variation in water conditions dating back to 1928. If Idaho Power were projecting or predicting future net power supply expenses, it would use a method entirely different from power supply expense normalization methodology.

Second, I would like to clarify Mr. Galbraith's testimony on page 1 that modeled annual net power supply expenses show an asymmetric distribution that is skewed towards high net power supply expenses. Mr. Galbraith's use of the term skewed may leave the wrong impression. In statistics, skew is a term of art that is used to describe the shape of certain distributions. A distribution is said to be skewed if observations create an unsymmetrical frequency distribution with a mode value that differs from the mean value. Recognition that a range of potential net power supply expenses was best represented by a skewed distribution was the very reason that the Company and its regulating Commissions in Oregon and Idaho changed power supply expense normalization methodology in 1982 as I have discussed earlier in my testimony. At that time it was demonstrated that the mean annual net power supply expense was higher than the annual net power supply expense for the median condition. The power supply expense distribution, with its different mean, median and mode values, by definition, is skewed. Perhaps Mr. Galbraith's intent was to remind the Commission that the mean of the power supply expense distribution is higher than the median of the distribution. However, if Mr. Galbraith is using the term skewed to imply that the distribution of modeled net power supply expenses is not representative of the true range of net power supply expenses then I must disagree and point out that such a conclusion is unsubstantiated by any evidence.

Q. Please explain how a distribution can have different mean and mode values.

A. As I have mentioned, both a distribution’s mean and mode are statistical measurements of central tendency. A mean is the mathematic average of observed values whereas a mode is the value observed most frequently. A third measure of central tendency is the median, which has an equal number of observations within the distribution that are greater than and less than the median value. In the case of net power supply expenses, the primary reason for having a mean that is different from the mode is related to the potential range of electricity prices. Electricity prices are a function of supply of electricity and demand for electricity. If demand for electricity is high and supply of electricity is low, prices are driven up without a theoretical upper bound. Conversely, if demand for electricity is low and supply of electricity is high prices are driven down with a limit of zero cost or free power. It is the limit or constraint on one end of the range of possibilities that bunches observations resulting in what is statistically referred to as a skewed distribution. Exhibit Idaho Power/202 shows a distribution of 21 observations with its corresponding mean, median and mode. By definition this distribution is skewed because it has differing values of mean and mode.

Q. You stated that actual annual power supply expenses over the last 22 years have been lower than the low extreme of modeled power supply expenses in this case on two occasions. How far below the modeled extreme of -$7.1 million in annual net power supply expenses has the Company’s actual annual net power supply expense fallen?

A. The lowest annual net power supply expense the Company has experienced was -$18.7 million, which is $13.6 million below the modeled extreme.

Q. You stated that actual annual power supply expenses over the last 22 years have also been higher than the high extreme of modeled power supply expenses in this case on three occasions. How far above the modeled extreme of $147.8 million in annual net power supply expenses has the Company's actual annual net power supply expense risen?

A. The highest annual net power supply expense the Company has experienced was $279.5 million, which is $131.7 million above the modeled extreme.

Q. Do you agree with Mr. Galbraith's testimony that the Company's modeling has overstated the Company's power supply expenses?

A. No. As I have shown, the range of modeled annual net power supply expenses is consistent with the actual net power supply expenses that the Company has actually experienced in the past. Actual historical data indicates that at the extreme of possible conditions, the Company's modeling far understates the high expense extreme while only moderately understating the low expense extreme.

Q. Mr. Galbraith states that he agrees with your testimony with regard to your expectation of regional electricity market prices in the $40 to $50 per MWh range for low water conditions, but suggests that the Company's modeling does not match your expectation of market prices during low water conditions. Please comment.

A. The Company's modeling of low water conditions does include purchases within the $40 to $50 per MWh range that I described in my expectation of regional electricity market prices that could be encountered under a low water condition. Mr. Galbraith's assessment is that the model understated the frequency of those higher cost purchases during low water conditions. I agree with Mr. Galbraith. As I have mentioned previously in my testimony, at the low water extreme the power supply model appears to have understated net power supply expenses rather significantly. This is consistent with Mr. Galbraith's assessment of the frequency of purchases made at higher prices during drought conditions.

Q. Mr. Galbraith states that he also agrees with your expectation of regional electricity market prices during high water conditions, but suggests that the Company's modeling does not match your expectation of market prices during high water conditions. Please comment.

A. Mr. Galbraith states that modeled surplus sales during high water conditions are often below $20 per MWh. That is my expectation of regional electricity market price during high water conditions and I believe my previous testimony was clear in that regard. Ten years ago, the monthly floor for electricity market prices during high water conditions was modeled at $7 per MWh. That monthly average floor is now modeled at over double the previous level at $17 per MWh. The $17 per MWh amount is the Company's expectation of electricity market price during high water conditions.

Q. Mr. Galbraith states that the high frequency of on-peak prices below $20 per MWh indicates that Idaho Power has understated regional electricity prices during high water conditions. Is his conclusion correct?

A. Mr. Galbraith confirms my testimony that it has been quite some time since the Company last experienced high water conditions. However, as recently as 2002, a year when water conditions were within the lowest 20 percent of water conditions, the annual average actual transaction rate for purchases and sales by Idaho Power was $23.65 per MWh. In 1999, a year when water conditions were just barely in the highest 20 percent of water conditions and one year prior to when the dysfunction in the California market became apparent, the annual average actual transaction rate for purchases and sales by Idaho Power was $20.62 per MWh. Based on that data, it is not unreasonable to expect that higher water conditions would result in even lower annual average transaction rates for purchases and sales. Mr. Galbraith's conclusion that Idaho Power has understated regional market prices during high water conditions is merely his contention that market prices will not again be as low as $20 during high surplus periods of time. Recent history does not support this contention.

Q. Have you prepared an exhibit that quantifies the actual annual average transaction rate for Idaho Power purchases and sales over the last 12 years?

A. Yes, Exhibit Idaho Power/203 shows a quantification of the actual annual average transaction rate for Idaho Power purchases and sales over the last 12 years.

Q. On page 9 of his testimony, Mr. Galbraith states that under average hydro conditions within Company modeling, the average daily Mid-Columbia on-peak price is $23.91 per MWh. Did the Company model a specific average hydro condition?

A. No. Mr. Galbraith has advised me that his testimony refers to the 1967 water condition that he characterizes as representative of the average water condition on page 6 of his testimony.

Q. Does comparison of either the annual average transaction rate for purchases and sales for the 1967 water condition or the annual average transaction rate for purchases and sales for all modeled conditions to the actual annual average transaction rates of each of the last 12 years suggest that the Company's power supply modeling has understated annual average transaction rates for normalization of power supply expenses?

A. No. As can be seen from the most recent 12 years of history, 75 percent of the actual average annual transaction rates for purchases and sales have been below the average annual transaction rate for the 1967 water condition and 58 percent of the actual annual average transaction rates for purchases and sales have been below the average annual transaction rate associated with the full 76 modeled conditions.

Q. What was the annual average transaction rate for purchases and sales for the 1967 water condition as determined within the Company's power supply modeling?

A. The modeled annual average transaction rate for purchases and sales for the 1967 water condition as determined within the Company's power supply modeling was $23.85 per MWh.

Q. What was the annual average transaction rate for purchases and sales over the full range of 76 water conditions as determined within the Company's power supply modeling?

A. The modeled annual average transaction rate for purchases and sales over the full range of water conditions as determined within the Company's power supply modeling was $22.90 per MWh.

Q. How does that $23.85 per MWh annual average transaction rate for purchases and sales for the 1967 water condition that Mr. Galbraith describes as representative of the average water condition compare to the actual annual average transaction rates for purchases as sales over the last 12 years?

A. The annual average transaction rate for purchases and sales of $23.85 per MWh associated with the 1967 water condition has been exceeded 5 times in the last 12 years (1998, 2000, 2001, 2003 and 2004). During two of those years, 2000 and 2001, market prices were artificially inflated in California adversely impacting Idaho Power and other northwest utilities and customers. Two years, 2003 and 2004 were among the lowest 20 percent of water conditions. The year 1998 was among the highest 20 percent of water conditions and had an annual average transaction rate for purchases and sales of $24.29 per MWh. One additional year, 2002, had an annual average transaction rate for purchases and sales of $23.65 which was lower than the 1967 water condition, but higher than the annual average of all purchase and sale transactions modeled under all water conditions. The remaining 7 years of history all had an annual average transaction rate for purchases and sales below $23.85 per MWh.

Q. Considering his opinion that Idaho Power has significantly understated electricity market prices, what does Mr. Galbraith suggest are "realistic" electricity market prices?

A. Mr. Galbraith suggests that April 30, 2004 forward prices for the calendar year 2005 with average monthly on-peak prices of $47.33 per MWh and monthly off-peak prices of $39.72 per MWh are the appropriate estimates of electricity prices under normal conditions.

Q. Do you agree with Mr. Galbraith when he states on page 15 of his testimony that forward prices for a time period one year into the future are representative of "the power market's expectation of average monthly spot market prices during calendar year 2005, under normal hydro conditions?"

A. Absolutely not. A forward price curve is a spot market representation of the prices various power marketers indicate would be future power purchases or sales prices at the date the forward price estimate is created. In other words, on April 30, 2004, the Company could have theoretically entered into transactions to purchase or sell during months of 2005 at the forward spot market prices identified on April 30, 2004. Given the prolonged period of northwest drought just prior to April 2004 and April 2004 forecasts of continued drought conditions, Mr. Galbraith's assumption that electricity markets would ignore current conditions and be willing in April to buy and sell power for the following year at rates reflective of normal hydro conditions is unrealistic. Given then-current drought driven market prices and no assurance of a return to average water conditions, common sense would suggest that the quoted future market prices reflected an unwillingness to enter into future purchase or sales transactions at less than then-current prices.

Q. In your answer, you stated that future spot market prices were representative of prices at which future transactions could theoretically be entered into at the time of the forward spot market price determination. Why did you use the word “theoretically” in your response?

A. Even though a forward spot market price can be estimated at any point in time, the Company is not necessarily able to enter into forward transactions at the stated forward spot market prices. For example, monthly forward price curves for April 2006 might be estimated today, but entities may currently only enter into transactions requiring purchase for the entire second quarter of 2006 at those quoted prices. This is an example of a forward monthly spot market that is currently not liquid (i.e. no transactions are currently occurring).

Q. Has Mr. Galbraith identified a range of market prices corresponding to the range of water conditions included in the Company’s normalization of power supply expenses?

A. No. Although, Mr. Galbraith suggests that it is reasonable to expect market prices in the $40 to $50 per MWh range under drought conditions and prices as low as $20 per MWh under high water conditions, he does not individually price independent water conditions. Mr. Galbraith simply re-prices all of the purchase and sales transactions that result from averaging the short and long positions of all 76 water conditions at the April 30, 2004 forward market prices for 2005. As a result, lower market prices associated with better than drought conditions are not considered at all. Rather, Mr. Galbraith takes high drought-related prices that Idaho Power is currently paying to acquire electricity during periods of deficiency and assumes those same high electricity prices will exist when the Company has surplus energy to sell.

Q. What is the effect of assuming that drought-driven forward market prices are representative of market prices during average water conditions?

A. Because the full range of water conditions has a greater level of surpluses than deficiencies, the use of Mr. Galbraith's of drought-driven market prices for all purchase and sales transactions regardless of water condition will significantly understate the reasonable level of normalized power supply expenses.

Q. Mr. Galbraith suggests that the market-clearing prices reflected in the Company's normalization of power supply expenses are not reasonably likely to occur during the rate period. Do you agree?

A. No. First, Mr. Galbraith takes a short-term view on rate setting that has not always been the case. The Company's current base rates in Oregon have not changed in the last 12 years. Second, Mr. Galbraith recommends using current electricity prices, which reflect current drought conditions as representative of prices "under normal conditions." This is a classic mixing of apples and bananas to arrive at an unrealistic result. Mr. Galbraith could just as easily stated that high, above average, or even average water conditions are not reasonably likely to occur during the period when the rates set in this case will be in effect. Such a statement would be consistent with his market price arguments and would suggest that those unlikely water conditions should be excluded from the rate-setting analysis.

Q. Mr. Galbraith's normalized net power supply expense recommendation is -$15.3 million, which you have characterized as unrealistic. Please elaborate.

A. In the test year, 2003, the Company's actual net power supply expenses were $150.0 million dollars. In 2004, the Company's actual net power supply expenses were $141.8 million. In the Company's March 2, 2005 deferral of excess power supply expenses application in Oregon, the Company estimated that March 2005 through February 2006 net power supply expenses will be $169 million. The Company recognizes that these high power supply expenses have occurred in large part due to drought conditions. As such, the Company has recommended normalized net power supply expenses in this case be set at $47.7 million. This is an amount that the Company believes is a reasonable representation of the average of the full range of possibilities of hydro conditions and corresponding electricity market prices. Commission Staff has recommended that normalized net power supply expenses in this case be set at negative $15.3 million based upon a belief that market prices reflected in modeling are not reasonably expected to occur in the period of time that rates are in place. Considering what we already know about 2005 hydro conditions, the Company does not believe that power supply expenses as low as $47.7 million are reasonably expected to occur in 2005 much less -$15.3 million. Given the Company's $169 million estimate of power supply expenses for the March 2005 to February 2006 time frame, the Company would need to see net power supply expenses of -$199.6 million in the following year to arrive at a -$15.3 average over two years. Two years of net power supply expenses at –$107.5 would be required to have a three-year average of -$15.3 million. The lowest net power supply expense the Company has experienced is -$18.7 million and yet the Staff recommendation for a normal expectation is -$15.3 million. The proposal suggests that approximately half the time in the immediate future the Company will have sufficient excess power that can be sold at high prices thereby creating lower power supply expenses than it has ever had. In light of current known water conditions, I believe such a scenario is extremely unrealistic. If the Staff's proposal for normalized net power supply expenses is accepted, I believe the Company will have no realistic opportunity to recover its reasonably incurred power supply expenses during the period of time that new rates will remain in effect.

Q. Is the CUB position on normalized net power supply expenses similar to the position of the Staff?

A. Yes. CUB states that the Company proposed $47.7 million of normalized net power supply expenses should be reduced by $66 million. As was similarly proposed by Staff, CUB recommends valuing all sales and purchase transactions at current drought-related market prices rather than recognizing that price is a reflection of supply and demand rather than a spot market forecast.

Q. Does OICIP provide a recommendation for normalized net power supply expenses?

A. OICIP witness Reading recommends rejection of power supply modeling, but then proposes possible repricing of modeled sales and purchase transactions as per his discussions with Commission Staff.

Q. Are the positions of the CUB and OICIP on normalized net power supply expenses materially different from the position of the Staff?

A. No, and as such my testimony on the Staff proposal for normalized net power supply expenses is equally applicable. CUB and OICIP recommendations on normalized net power supply expenses should also be rejected.

Q. When does the Company anticipate its next general rate application in Oregon?

A. As I mentioned in my direct testimony, the Company envisions a period of significant investment by Idaho Power to continue to serve the growing needs of its customers. The Company anticipates filing a 2005 test year Oregon general revenue requirement case as early as October of this year. If that schedule holds, the rates established in this case might only be in effect for one or two years.

Q. Given the probable short-term nature of prospective rates set in this case, is it reasonable to adopt Staff, CUB, or ICIP recommendations to establish rates that assume the Company can supply energy to all of its customers for the next two years at negative power supply expense?

A. No. I believe that the Company's proposed $47.7 million of normalized net power supply expenses is the reasonable level of power supply expenses for near-term prospective rate setting. This is the same level of power supply expenses that were approved for ratemaking purposes in Idaho after the Idaho Commission Staff acknowledged that the Company's proposed power supply expense level was probably too low. No other party contested the Idaho Staff's conclusion. Mr. Galbraith, CUB and ICIP are recommending a departure from power supply normalization methodology that has been utilized in setting Idaho Power's rates in Oregon and Idaho for over 20 years. The contention that the Company's proposed normalized power supply expense level is overstated is not supported by evidence. The assumption that drought-related market prices are representative of market prices under normal conditions is unrealistic. Unless next winter provides far greater than normal precipitation, Idaho Power will be a net buyer of power for the next two years with no opportunity to have sufficient surplus sales with profits exceeding the expense of serving jurisdictional customers.

DANSKIN

Q. In his testimony, OICIP witness Dr. Reading testifies that the cost of energy from the Danskin Power Plant is high and as a result he recommends that the Commission not allow the Danskin Power Plant to be included in the Company's ratebase. Would you please address Dr. Reading's recommendation.

A. There are three principal reasons why I believe this Commission should reject Dr. Reading's recommendation. First, in discussing the cost of energy from Danskin, Dr. Reading fails to acknowledge that the Danskin Power Plant is a peaking plant. That means Danskin's cost per megawatt-hour was always expected to be higher than the cost per megawatt-hour for a base load generating plant. Also, when the Idaho Commission approved inclusion of Danskin investment in ratebase, it found that the Danskin Plant is generating at levels consistent with the Company's initial estimates.

Second, Dr. Reading fails to acknowledge that a peaking resource like the Danskin Power Plant provides independent value by contributing to Idaho Power's system reliability. As I noted in my direct testimony, Danskin supplied badly needed capacity in 2002 and 2003. This was also the case in 2004 and will be the case this summer as well. If current projections of hydroelectric generating conditions for 2005 remain unchanged, it is possible that the Danskin Power Plant could provide the capacity margin needed to avoid outages and interruptions of customer service this summer.

Finally, Dr. Reading made the identical arguments and recommendation that Danskin be excluded from ratebase to the Idaho Public Utilities Commission in the Company's last general rate case which concluded in September of 2004. The Idaho Commission was very familiar with the events that led up to the development of the Danskin Power Plant and based on that knowledge, the Idaho Commission refused to accept Dr. Reading's recommendation.

Q. Dr. Reading's testimony focuses on the high costs of the Danskin Power Plant. How do you explain those costs in terms of the decision to build and operate Danskin?

A. First, no one should be surprised that the per MWh cost of a peaking plant like Danskin is greater than the cost of energy from a base load generating plant. Second, as the Idaho Commission noted in Order No. 28733 when it issued the Certificate of Public Convenience and Necessity authorizing construction of Danskin, the standard for evaluating the prudency of the decision to proceed with construction of Danskin must be viewed in the context of the facts known *at that time*. When the decision to build Danskin was made, the wholesale market price of power was very high. Idaho Power was faced with the prospect of paying extremely high prices for energy to meet load. In February of 2001, Mid-Columbia forward prices for August through December 2001 were $350 - $415/MWh for heavy load hours, and $275 to $300/MWh for light load hours. Therefore, Danskin was considered valuable for its ability to contribute to reliability and for its potential to sell into the wholesale market which would have served to lower power supply costs to retail customers. Had the quoted forward prices held, Danskin would have likely operated at full load for the remainder of 2001. In fact, if gas and power prices had remained high in the winter of 2001, Danskin's operation could have reduced net power supply costs to Idaho Power's customers by about $15 million dollars per month. Given these actual market conditions and Idaho Power's potential inability to import sufficient energy due to transmission constraints, a down payment on the turbines was made in early February 2001 and the purchase was completed by mid-March 2001. The wholesale power markets subsequently moved lower, but the project was continued based on the need for a true peaking resource to increase system reliability.

Q. Dr. Reading is critical of the Company's initial estimates of the number of hours Danskin would operate. Is this criticism valid?

A. No. As the Idaho Commission noted in its Order No. 29505 when it approved the inclusion of Danskin investment in Idaho ratebase, the number of hours Danskin has operated is consistent with the projected hours of operation discussed when the Idaho Commission issued its Certificate of Public Convenience and Necessity for Danskin. It is also important to remember that the decision to build Danskin was driven by reliability concerns as much as cost savings. The Company has a continuing obligation to serve its customers even when inbound transmission constraints block access to wholesale markets during peak times.

Q. Dr. Reading testifies that the Company should have cancelled the Danskin Power Plant in the summer of 2001. Would it have been prudent for the Company to cease construction of the project after spot market power prices dropped in the summer of 2001?

A. No. There are several reasons why it would not have been prudent or reasonable for Idaho Power to cease Danskin construction as Dr. Reading now recommends. First, Dr. Reading only makes a passing reference to the fact that at the time wholesale prices dropped in the summer of 2001 there was still tremendous uncertainty in the Western electricity markets. While looking backward from today shows that spot wholesale prices began decreasing in June of 2001, forward energy prices at that point were still well above historical energy prices. Additionally, there was considerable uncertainty as to how long the FERC-imposed price caps would remain in place and what affect their removal might have on market prices. Finally, when one considers the extremely adverse water conditions that existed in the fall of 2001, canceling a generation resource in the face of very uncertain wholesale market prices and real transmission constraints would have been very risky. In short, without the benefit of Dr. Reading's 20/20 hindsight, I believe it would have been extremely imprudent to abandon Danskin in mid-stream as Dr. Reading urges.

Q. In addition to the operating and reliability risks associated with cancellation, would there have been financial ramifications of cancellation in mid-stream?

A. Of course. By the end of June 2001 Idaho Power had already incurred approximately $33.5 million in costs associated with the Danskin Power Plant. That amount represents approximately 65 percent of the total cost of the project. In addition, cancellation would have obligated the Company to pay substantial cancellation charges to various contractors. Considering the uncertainty in water conditions and the wholesale power markets at the time, and considering the fact that approximately two-thirds of total project costs had been incurred, plus the additional costs that would be incurred to terminate the project, Dr. Reading's suggestion that the Company should have cancelled the project and then, presumably, requested recovery of the cancellation costs from customers is unreasonable.

Q. Are there other system benefits Danskin provides besides meeting peak load demand?

A. Yes. Having generating resources providing voltage support close to the Company's load center (which includes Ontario, Oregon as well as the Boise area) helps to prevent a phenomenon known as voltage collapse. This happens during periods of peak customer demand when load is being served by generators remote to the load center since the reactive power necessary to maintain voltage is difficult to transmit over long transmission lines.

Danskin also provides emergency reliability for the system in the case of transmission loop flows, unplanned outages and to provide required reserve margins. In fact, during the 2003 peak summer season, even with Danskin running at full output, the Company was unable to maintain its desired reserve margins during some heavy load hours, meaning that a single system contingency would have required service curtailments.

Q. Has Danskin operated effectively to carry customer loads during the peak summer months?

A. Yes. For example, during July of 2002 Danskin's units operated a total of 481 hours and during July of 2003 Danskin was operated a total of 567 hours.

Q. What is your expectation for the operation of Danskin during 2005 and beyond?

A. Danskin will continue to dispatch to meet peak loads and for reliability during the summer of 2005 and beyond. While it is true that with the addition of the new Bennett Mountain CT, Danskin will generally dispatch after Bennett Mountain, Danskin will still dispatch during peak times when transmission constraints are encountered, especially as peak load grows over time. Summer peak load is growing on the order of 80 to 85 MW per year.

While it is impossible to predict with precision what hours Danskin will run this summer, the Company has purchased gas to fuel operation sufficient to generate approximately 58,000 MWhs of generation. This equates to 650 hours of full load operation for Danskin. There are a number of reasons why Danskin is still an extremely valuable resource for the Company in 2005 and beyond:

1. It is still a hedge for runaway wholesale prices.

2. System emergencies or transmission constraints (requiring additional internal generation) can occur at any time.

3. Idaho Power anticipates operating both Danskin and Bennett Mountain during the summer of 2005 to meet peak hour loads.

4. Danskin will most likely operate during a portion of the Heavy Load Hours (HLH) during peak load days. This method of operation allows Idaho Power to dispatch Danskin to serve only the peak hours avoiding

the need to purchase from the market during super-peak hours. It is not uncommon for hourly purchases during summer super-peak hours to sell for a premium of 30% over the standard 16-hour product price. So, if the 16 hour block sells for $60/MWh, hourly purchase prices may be $78/MWh, or higher.

Q. Does the Company's 2004 Integrated Resource Plan show a continuing need for the Danskin Plant?

A. The 2004 Integrated Resource Plan shows that peak hour transmission deficits from the Pacific Northwest continue to grow. Even with the Danskin and Bennett Mountain plants in operation, the projected peak hour transmission deficits from the Pacific Northwest reach 510 MW in 2010, and continue to grow in subsequent years. Given the projected peak hour transmission deficits, the 2004 IRP shows a need for even more peaking resources located inside of the Company's control area near the Ontario-Boise load. In fact, in compliance with the schedule in the 2004 IRP, the Company has just issued a request for proposals for another peaking resource to provide at least 88 MW of peaking capacity in the summer of 2006.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 201

GREGORY W. SAID

22 Year Range of Net Power Supply Expenses

22 Year Range of Net Power Supply Expenses

Year	Actual Net Power Supply Expenses	Modeled Net Power Supply Expenses
2004	141,785,476.65	N.A.
2003	149,986,296.32	98,754,336.63
2002	109,315,319.67	112,664,668.81
2001	279,500,718.31	128,144,919.30
2000	225,900,802.63	50,316,707.89
1999	34,706,905.41	21,666,501.14
1998	14,593,266.14	12,646,712.40
1997	12,915,931.40	20,084,828.17
1996	44,888,118.69	25,844,510.25
1995	39,329,994.44	32,837,939.25
1994	95,381,913.45	97,218,857.40
1993	42,402,129.49	37,391,774.20
1992	119,055,539.89	147,846,520.57
1991	66,927,240.84	115,419,523.12
1990	78,703,731.00	108,370,239.16
1989	45,970,526.24	49,886,419.12
1988	80,107,299.82	110,149,761.26
1987	52,748,647.85	63,804,002.62
1986	1,977,103.12	6,161,363.82
1985	3,455,827.20	25,150,851.79
1984	(18,665,349.27)	(7,052,487.99)
1983	(16,712,629.06)	(1,959,131.24)

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 202

GREGORY W. SAID

Distribution of 21 Observations with its Corresponding Mean, Median and Mode

Distribution of 21 Observations with its Corresponding Mean, Media and Mode

Observation Value Number	Observation Value
1	20
2	23
3	26
4	27
5	27
6	27
7	29
8	30
9	30
10	31
11	32
12	37
13	39
14	43
15	45
16	47
17	54
18	60
19	62
20	67
21	70

Mean	39.3
Median	32
Mode	27

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 203

GREGORY W. SAID

12 Year Actual Annual Average Transaction Rate for Purchases and Sales

12 Year Actual Annual Average Transaction Rate for Purchases and Sales

	Purchases MWH	Sales MWH	Total MWH	Purchases $	Sales $	Total $	Purchase Rate	Sales Rate	Blended Rate
2004	3,596,618.00	2,761,665.00	6,358,283.00	$155,801,649	$117,277,605	$273,079,254	43.32	42.47	42.95
2003	2,729,368.00	1,380,177.00	4,109,545.00	$109,664,321	$59,575,782	$169,240,103	40.18	43.17	41.18
2002	2,225,699.00	1,508,710.00	3,734,409.00	$47,380,088	$40,935,363	$88,315,451	21.29	27.13	23.65
2001	2,727,665.00	1,765,890.00	4,493,555.00	$385,474,936	$203,939,758	$589,414,694	141.32	115.49	131.17
2000	3,449,779.00	3,897,934.00	7,347,713.00	$342,481,544	$210,795,446	$553,276,990	99.28	54.08	75.30
1999	2,200,498.00	5,305,036.00	7,505,534.00	$51,433,028	$103,342,848	$154,775,875	23.37	19.48	20.62
1998	19,745,790.00	23,151,057.00	42,896,847.00	$485,242,271	$556,886,255	$1,042,128,527	24.57	24.05	24.29
1997	8,849,011.00	11,928,419.00	20,777,430.00	$163,228,413	$221,583,966	$384,812,380	18.45	18.58	18.52
1996	2,302,910.00	3,397,035.00	5,699,945.00	$26,407,822	$44,853,207	$71,261,029	11.47	13.20	12.50
1995	1,502,076.00	2,014,933.00	3,517,009.00	$16,586,318	$31,947,026	$48,533,344	11.04	15.86	13.80
1994	1,744,047.00	1,413,650.00	3,157,697.00	$34,240,544	$33,746,243	$67,986,786	19.63	23.87	21.53
1993	706,191.00	2,590,719.00	3,296,910.00	$12,321,381	$57,690,363	$70,011,744	17.45	22.27	21.24

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO CUSTOMERS IN THE	)
STATE OF OREGON	)
______________________________________	)

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

DENNIS E. PESEAU

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am President of Utility Resources, Inc. (URI). URI has consulted on a number of economic, financial and engineering matters for various private and public entities for more than twenty years.

Q. DOES EXHIBIT 301 BRIEFLY SUMMARIZE YOUR BACKGROUND AND EXPERIENCE?

A. Yes.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON?

A. Yes. I have testified before this Commission on numerous occasions on behalf of the OPUC staff, various intervenors and regional utilities dating back to the mid-1970s.

<u>Net Variable Power Costs</u>

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to address the single, but somewhat complex issue of the level of dollars requested by Idaho Power, and the counter positions offered by OPUC staff, the OICIP and CUB, regarding the Company's net variable power costs ("net power costs") in these proceedings.

As CUB's position on this issue is similar to Staff's, and the OICIP tends to agree with Staff, I do not separately address these positions.

As the issues, concepts, assumptions and calculations inherent in estimating "normalized" net power costs of any Pacific Northwest electric utility are necessarily technical, I will to the extent possible develop my arguments initially on a "common sense of the outcome" basis, before delving into some of the more technical aspects.

Q. WHAT DO YOU MEAN BY A "COMMON SENSE OF THE OUTCOME" APPROACH?

A. Whenever administrative proceedings such as these must consider a highly complex issue such as estimating normalized net power costs, simple reality checks are useful. In a region like the Northwest where such costs are largely determined by widely and statistically unpredictable hydrological or streamflow conditions varying from year to year, one must resort to complicated and mathematical statistical estimation methods. And, when swings of several tens-of-millions of dollars in power costs can result among parties as is the case here, some way of checking the simple reasonableness of the parties' proposals is valuable.

Q. HOW DO YOU PROPOSE TO EVALUATE THE REASONABLENESS OF THE DISPARATE NET POWER COST RECOMMENDATIONS MADE IN THESE PROCEEDINGS?

A. I begin with a general consideration of what I presume is the objective of the whole power cost normalization effort by Idaho Power and other parties. I presume the objective is to estimate that single level of net power costs that would reflect the average production costs incurred by Idaho Power over multiple water years.

And, while we understand that exactly "average water conditions" will seldom prevail during a test year, hopefully over time the methods of estimating normalized power costs will tend toward the power costs actually incurred. If there is no systematic bias upward or downward in the normalized power cost estimates, ratepayers and shareholders are well served in that actual power costs are recouped over time.

Below I evaluate the reasonableness of Idaho Power's and OPUC staff's test year net power cost recommendations on the basis of how well these estimates would recover, or not, actual power costs on average over the past twenty-one years. This simple general test of the accuracy of Idaho Power's compared with Staff's estimates of net power supply costs is followed by a number of technical modeling considerations, as well as a brief discussion of how these same issues were addressed in Idaho Power's recent general rate case in the state of Idaho, Case No. IPC-E-03-13.

Q. WHAT CONCLUSIONS HAVE YOU REACHED ?

A. I conclude that:

1. OPUC Staff witness Mr. Galbraith's recommendation to reduce Idaho Power's net power supply costs by $63 million per year would result in the under-collection of these expenses approximately 90% of the time.

2. Staff's April 30, 2004 forward price curve, which it

uses as a surrogate for normalized market prices, instead reflects the expectation of poor water conditions and is therefore not valid as an indicator of regional market prices that Idaho Power could expect under average water conditions.

3. Staff's proposed $63 million downward adjustment to normalized power supply costs is largely an artifact of failing to price Idaho Power's normalized surplus power sales at lower off-peak values indicative of its typical daily load shapes.

4. Idaho Power's proposed $47.7 million of normalized net power supply expenses in this case is consistent with the level of these same expenses that have been in its Oregon rates for more than a decade, and are the same as recently approved by the Idaho Public Utilities Commission in Idaho Power's general rate case, Case No. IPC-E-03-13 .

5. OPUC Staff witness Mr. Galbraith raises a number of concerns he has with the operation of and assumptions for the Company's AURORA Model. These questions and concerns should be addressed in a technical forum outside this general rate case.

<u>Power Cost Estimation</u>

Q. WHY, IN YOUR OPINION, IS THERE SUCH A LARGE ISSUE WITH RESPECT TO NET POWER SUPPLY EXPENSES IN THESE PROCEEDINGS?

A. As with other categories of expenses and rate base items, there is a need to normalize to a test year. Power supply expenses reflect those costs that vary in meeting actual utility loads. They are comprised primarily of fuel and purchased power costs, less any revenues received from surplus sales to other entities. For a hydro-based utility such as Idaho Power, however, the estimation of fuel expenses, purchased power and sales is greatly complicated by the great variability in hydro or water conditions from year to year. And, due to the fact that power supply costs are not symmetric around average water conditions, significant statistical calculations are necessary to predict power costs existent with average water. But in the present case, there is a remarkably close agreement among parties on the level of estimated total gross power costs expected to be incurred by Idaho Power on a test year basis.

For example, Idaho Power shows an expected level of test year total power costs of $110.8 million, defined as total test year fuel and purchased power costs exclusive of surplus revenues. Mr. Galbraith's equivalent figure is $111.9 million, a difference of only $1.1 million.[1] Thus, there is virtual agreement on test year total power costs.

Q. GIVEN THE CLOSE AGREEMENT BETWEEN COMPANY AND STAFF ON TOTAL TEST YEAR POWER COSTS, WHAT EXPLAINS THE $63 MILLION DIFFERENCE IN NET POWER SUPPLY EXPENSES BETWEEN COMPANY AND STAFF?

A. As I noted above, test year net power supply expenses are

[1] These figures are developed on Idaho Power Exhibit 13, page 1 of 77 and on Staff Exhibit 202, page 27, by adding the expenses of all thermal generating plants and purchased power costs.

derived by subtracting from the above total power costs those revenues expected to be received by the Company from surplus sales to other entities. It is the difference in modeled levels of revenues from surplus sales that accounts for most of the $63 million difference in net power supply costs between Idaho Power and OPUC Staff. Staff predicts that the Company, under normal hydro conditions could sell $127.2 million in surplus energy to others, while Idaho Power predicts normalized surplus sales of $63.1 million.

<u>Predicted versus Historic Net Power Costs</u>

Q. WHAT IS THE LEVEL OF NET POWER SUPPLY COSTS REQUESTED BY IDAHO POWER IN THIS CASE?

A. $47.7 million.

Q. WHAT IS THE LEVEL OF NET POWER SUPPLY COSTS RECOMMENDED BY STAFF IN THIS CASE?

A. A negative $15.3 million. In other words, Staff predicts that under normalized hydro conditions, Idaho Power's surplus sales revenues will exceed its total power production costs, including its coal and natural gas purchases, as well as its purchased power costs, by $15.3 million.

Q. OVER THE LAST TWENTY YEARS, HOW DOES THE COMPANY'S $47.7 MILLION, AND STAFF'S NEGATIVE $15.3 MILLION OF NORMALIZED NET POWER SUPPLY COSTS COMPARE WITH ACTUAL NET POWER SUPPLY COSTS?

A. My Exhibit 302 is a graphic representation of Idaho Power's and Staff's recommended normalized power supply costs. The Company's requested normalized costs is shown as a horizontal line of $47.7 million and Staff's is shown as a horizontal line at a negative $15.3 million.

Superimposed on these two horizontal lines are two historic line segments showing Idaho Power's actual net power supply costs, and the net power supply modeled in Company Exhibit 13, annually from 1983-2003. The modeled line segments on my exhibit show the year-by-year changes in net power supply costs under the actual water conditions experienced in each year, and the resulting net power supply costs at the level of loads and resources existing today.

Q. WHAT DOES YOUR EXHIBIT 302 SHOW?

A. First, by comparing the normalized, horizontal lines that reflect the Company's and Staff's normalized net power supply cost recommendations, an assessment can be made as to whether either recommendation tends to show any inherent statistical bias. This can be done by observing whether or not the historic year-by-year actual net power costs experienced by Idaho Power tend to be above and below the normalized net power cost estimate on roughly an equal basis. That is, if an estimate truly reflects normal or average net power costs, we would expect a tendency for the individual years making up the average to be on each side of the average with a comparable frequency.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF EXHIBIT 302?

A. Exhibit 302 charts 21 years of actual Idaho Power net power costs, 1983-2003. Referencing the horizontal line depicting Idaho Power's estimate of $47.7 million in normalized net power costs, 11 years of actual historical net power costs fall below the horizontal line and 10 years of net power costs are above, or are higher than the $47.7 million.

Referencing the horizontal line depicting Staff's negative $15.3 million recommended net power costs, only the two years 1983 and 1984 show actual negative power costs roughly equal to Staff's proposal. The remaining 19 years from 1985 to 2003 above the Staff horizontal line indicate that Idaho Power's actual annual historic net power costs are all higher than proposed by Staff. I conclude that Staff's estimate is unusually low and has a very low probability (2 in 21) of accurately predicting net power costs.

Q. IS THERE ANYTHING REMARKABLE ABOUT THE TWO WATER YEARS THAT OCCURRED IN 1983 AND 1984?

A. Yes. 1983 and 1984 are the two highest water years on record. Only in these two highest water years can any level of net power costs close to those recommended by Staff be expected.

Q. WHAT ELSE DOES Exhibit 302 SHOW?

A. Exhibit 302 also shows that the year-by-year modeled net power costs estimated by Idaho Power track well with the year-by-year actual net power costs.

<u>Staff's Estimates of Normalized (forward) Market Prices</u>

Q. HOW DOES STAFF EXPLAIN THE DIFFERENCE BETWEEN ITS PROPOSAL REGARDING TEST YEAR NORMALIZED

ELECTRIC MARKET PRICES AND THE COMPANY'S ASSUMPTIONS FOR NORMALIZED ELECTRIC MARKET PRICES?

A. Staff attributes the difference between its estimate of surplus sales revenues of $127.2 million and Idaho Power's amount of $63.1 million entirely to the assumed surplus sales market price that Idaho Power would be in a position to charge under normal water conditions. I say this because Staff and Company use the same figure for the quantity of surplus energy sales made of 3.025 million megawatt hours. Thus only the unit price of such sales can account for the large difference in normalized surplus sales

The issue is whether Staff's higher assumed expected market price that Idaho Power might receive for its surplus energy is more accurate than the Company's under normalized conditions.

Q, HOW DOES IDAHO POWER DETERMINE ITS ESTIMATE OF THE PRICES AT WHICH IT WILL BE ABLE TO SELL ITS TEST YEAR NORMALIZED QUANTITIES OF SURPLUS ENERGY?

A. Test year market prices are determined within the operations of the Company's AURORA Model. From the publicly available documentation for the AURORA model, I understand the model to operate on a regional basis, screening all regional resources and operational constraints, such as transmission, in a manner that meets the combined regional utilities' loads at the lowest cost. The model is described to respond to hourly load shapes with market prices being solved simultaneously to clear regional supply and demand.

Q. WHERE ARE THESE MARKET PRICES FOR IDAHO

POWER'S NORMALIZED TEST YEAR SURPLUS SALES REVENUES SHOWN IN THE COMPANY'S FILING?

A. The market prices at which Idaho Power sells its surplus energy are derived by dividing the total revenues the Company receives for surplus sales, divided by the quantity sold.

Idaho Power's Exhibit 13 contains 77 sets of such monthly prices. Page 1 of Exhibit 13 summarizes these market prices, averaged over 76 historic actual water conditions. Pages 2-77 of Exhibit 13 provides the 76 year-by-year individual power cost and market purchases and sales information, 1928-2003.[2]

As an example, I have handwritten into the original page 1 of Exhibit 13 the computed market prices under normalized conditions, which is attached as my Exhibit 303.

Q. HOW DOES STAFF DETERMINE ITS ESTIMATE OF THE PRICES AT WHICH IT BELIEVES IDAHO POWER WILL BE ABLE TO SELL ITS TEST YEAR NORMALIZED QUANTITIES OF SURPLUS ENERGY?

A. On Pages 14-15 of Mr. Galbraith's direct testimony, he explains that due to his criticisms of the AURORA Model and/or Idaho Power's inputs and assumptions pertaining to this model, he substitutes a single set of flat monthly market purchase and surplus sales prices given in forward price curves from April 30, 2004.

[2] Market purchase prices by month are derived by dividing line 20 by line 17 and market sales prices are derived by dividing line 27 by line 24 for each of the 77 pages on Company Exhibit 13.

I attach as my Exhibit 304 Page 27 of Mr. Galbraith's Exhibit 202 with my handwritten verification of the monthly flat prices he used to price both market purchases and market sales.

Q. WHAT ARE APRIL 30, 2004 ELECTRICITY FORWARD PRICE CURVES?

A. April 30, 2004 electricity forward price curves are summaries of what the market on April 30, 2004 assesses will be market prices for some period into the future. In this case the future period is calendar year 2005.

Q. WHY DOES MR. GALBRAITH USE APRIL 30, 2004 FORWARD PRICE CURVES?

A. On Page 15, Lines 1-9, Mr. Galbraith explains his proposal to use the April 30, 2004 forward price curves.

"First, using the company's April 30, 2004 price curve is consistent with the period the company used to make adjustments for known ratebase additions in this docket. **Second**, specific information regarding the 2005 hydro condition was unavailable at this time. Therefore, the forward prices reflected the power markets' expectation of average monthly spot market prices during calendar year 2005, under normal hydro conditions. **Finally**, these forward market prices are more representative of the average level of spot market prices for the period rates from this docket are expected to be in effect, than the modeled market-clearing prices underlying Idaho Power Exhibit 13." (emphasis added)

Q. IN YOUR OPINION DO THESE THREE EXPLANATIONS

SUPPORT THE USE OF THE APRIL 30, 2004 FORWARD PRICE CURVES AS REFLECTING NORMALIZED 2005 MARKET PRICES?

A. No. The April 30, 2004 forward price curve reflects expected prices above those that would be expected to prevail under normalized or average water conditions simply because the April 30, 2004 forward curves reflect below normal water conditions that have prevailed for several years. In fact, the region has not experienced a water year at or above average since 1999. Until the region experiences one or more years of average or above water, forward price curves will continue to reflect the higher prices associated with poorer water conditions, as they now do.

Q. DOESN'T MR. GALBRAITH SUGGEST THAT SINCE "SPECIFIC INFORMATION REGARDING THE 2005 HYDRO CONDITION WAS UNAVAILABLE" ON APRIL 30, 2004, THAT THE MARKET'S EXPECTATION WAS FOR A RESUMPTION OF NORMAL HYDRO CONDITIONS?

A. Yes. However, the market did not expect a resumption of normal water for at least two reasons.

One, the monthly forward price curves subsequent to April 30, 2004 according to Mr. Galbraith's theory should have exhibited a pronounced increase to higher prices if indeed the April 30, 2004 forward curves really reflected an expectation of average water. In fact, subsequent months forward price curves were consistent with the prices in the April 30, 2004 even as the summer and fall of 2004 continued with dry conditions. This indicates that, as we would expect, the April 30, 2004 forward price curves reflected continued poor water conditions.

Q. PLEASE EXPLAIN HOW PRICE CURVES SUPPORT YOUR CONCLUSION.

A. Based on the Company's response to Staff data request No. 274, I prepared Exhibit 305 *[Confidential].* Exhibit 305 overlays the forward price curves from April 30, 2004 to March 2005. It is commonly held that these forward price curves reflect all pertinent supply and demand information currently known for the future periods pricing. These forward curves often form the basis for current electricity contracts made for future deliveries. If on April 30, 2004 the market consensus was for a resumption of normal water conditions for the upcoming fall and winter, forward prices at the time would have been significantly lower than for the subsequent months forward curves for the upcoming fall and winter period that reflected the ultimate realization that water conditions were in fact not going to be average or normal, but in fact were worsening.

If, however, the April 30, 2004 forward price curve already reflected the expectation of lower than average water conditions, this and subsequent months' forward curves would be relatively consistent. Exhibit 305 shows that the prices reflected in the forward curves were consistent at least until the snowpack reports of January 2005, which reflected even poorer anticipated water. The conclusion, then, is that the April 30, 2004 forward price curve reflected poorer than average water, and higher market prices than would prevails under average hydro conditions. These market prices should not be used as a surrogate for average water surplus energy sales prices.

Q. WHAT IS THE SECOND REASON YOU CITE AS

EVIDENCE THAT THE APRIL 30, 2004 FORWARD PRICE CURVE USED BY MR. GALBRAITH DOES NOT REFLECT PRICES UNDER NORMAL WATER CONDITIONS?

A. The second reason involves certain issues in the mathematical statistics of how historical water years have behaved year to year. We know, for example, that the 2003-2004 water year was below normal. The statistical issue I address is whether or not year-to-year water conditions tend to vary randomly about the average, or tend to cycle about the mean or average. By this I mean the tendency for a bad or good water year to reoccur for one or more additional years, or flip-flop from good to bad to good. This is an important issue because Mr. Galbraith argues that the forward price curves he uses as of April 30, 2004 assume resumption of normality despite the then (and present) very poor water conditions.

The more formal statistical question posed here is whether or not year-to-year water conditions vary systematically above and below the longer-term average year by year, or whether water conditions are “autocorrelated,” tending to remain below and above historic means for periods of more than a year at a time.

Q. HAVE PRIOR WATER YEAR STUDIES FOUND HYDRO CONDITIONS TO BE AUTOCORRELATED FROM YEAR TO YEAR?

A. Yes. In fact, the issue of autocorrelation in water conditions was exhaustively examined in the Idaho Power Case No. U-1006-265 general rate case. There the Idaho Public Utilities Commission found that the statistical evidence strongly supported the autocorrelation in streamflows and hydro generation.[3]

Q. HAVE YOU CONDUCTED STATISTICAL AUTOCORRELATION ANALYSIS FOR THE HISTORICAL HYDRO DATA IN THE PRESENT CASE?

A. Yes. My Exhibit 306 provides a correlation matrix of annual hydro production for Idaho Power. The exhibit indicates that there is significant autocorrelation between successive years hydro production for at least two to three years of production.

Q. IN PLAIN TERMS, WHAT DOES THIS STATISTICAL ANALYSIS SHOW?

A. The plain interpretation of my autocorrelation analysis is that the statistical evidence strongly indicates that given the current actual water year, that the next water year does <u>not</u> have a 50% chance of being above or below average. In fact, the evidence shows that, if an actual hydro condition for a particular year is above (below) average, that there is a 70% chance that the next year's hydro condition will be above (below) the average. Thus, water years tend to cycle above and below the long-term average, rather than fluctuate randomly.

This analysis supports my conclusion that the April 30, 2004 forward price curve could not have reflected an expectation that the 2005 water year

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[3] The evidence in this case was based on thorough analysis of autocorrelation and application of autoregressive integrated moving average models.

would be normal.

Q. CAN YOU REFERENCE SOME MORE OBVIOUS AND READILY VERIFIABLE EVIDENCE THAT GOOD WATER YEARS AND BAD WATER YEARS EACH TEND TO OCCUR FOR MORE THAN ONE YEAR AT A TIME?

A. Yes. My Exhibit 307 is a graph of chronological Idaho Power Annual Hydro Generation by Hydro Condition.

The simple reflection of autocorrelation of water years can be explained by reference to groups of adjacent hydro conditions on this graph to see if, for prolonged periods, year-to-year hydro generation remain above or below average.

Most recently, this autocorrelation is supported by noting the following sequences. Each hydro year 1990, 1991, 1992, 1993 and 1994 were all back to back below average water years. Hydro years 1995, 1996, 1997, 1998 and 1999 were all back to back above-average water years. And finally, hydro years 2000, 2001, 2002, 2003 (as well as 2004) were all below average water years. My Exhibit 307 shows the tendency for subsequent water years to cycle rather than move randomly about the average.

Given the tendency for hydro conditions to persist above and below average, Mr. Galbraith's assumption that a full return to normal water was expected on April 30, 2004 is not supportable. I continue to conclude that the forward price curve on April 30, 2004 contains expected prices well above those that would be expected if 2005 experiences normal water.

Surplus Energy Sales and Off-Peak Prices

Q. WHAT IS THE ISSUE WITH RESPECT TO STAFF'S PRICING OF IDAHO POWER'S NORMALIZED PURCHASED POWER AND ITS SURPLUS ENERGY SALES?

A. As discussed at Page 15, Lines 17-20 of Staff's Exhibit 200, Mr. Galbraith reprices Idaho Power's estimated surplus energy sales at a "flat" or average monthly market price taken from the April 30, 2004 forward price curves. Flat prices refer to Staff's averaging of the on-peak and off-peak forward price curves. But it is not valid to estimate a single price for both the Company's purchased power and its surplus energy sales.

Q. PLEASE EXPLAIN WHY USE OF A SINGLE PRICE IS NOT VALID.

A. Due to the daily load shapes that Idaho Power faces in all seasons of the year, it does not receive the same price for its energy sales as it has to pay for market purchases. This is because the Company's daily peak loads occur during the day when it has to purchase power at on-peak prices. Similarly, its resources with which it makes surplus energy sales tend to be available in the off-peak periods and can be sold only at the then-prevailing off-peak prices. Using Staff's flat price for energy sales exaggerates the surplus sales revenues when most of these sales must be sold into the softer off-peak markets.

This can be seen, for example, by comparing my handwritten market prices on my Exhibit 303 for the on-peak purchases made by Idaho Power to the largely off-peak prices received by Idaho Power for its surplus energy sales.

Q. WHAT ARE THE TYPICAL SHAPES OF DAILY LOADS FACED BY IDAHO POWER?

A. My Exhibit 308 shows a Company daily load curves for a typical summer peak day. As shown, there is an approximate 1000 MW difference in loads between light and heavy loads periods. Economic dispatch leads Idaho Power to typically make market power purchases during on-peak periods and selling into the market in shoulder and off-peak periods. This is why Idaho Power's off-peak sales quantities tend to be nearly fifteen times the quantity of energy it purchases. Given this, Staff should have repriced its assumed quantities of Idaho Power surplus energy sales at or near the off-peak prices, not at a flat twenty-four hour price.

Q. WHAT DIFFERENCE IN STAFF'S ESTIMATED NET POWER SUPPLY EXPENSES WOULD HAVE RESULTED FROM THIS REPRICING?

A. The answer depends upon the exact percentage of the mix of on-peak to off-peak quantities of surplus energy sales assumed. But, even assuming that the April 30, 2004 price curves are appropriate, an assumption I criticize above, and assuming that 100% of Idaho Power's surplus energy sales are made during shoulder and off-peak periods, Staff's net power supply expense estimate would have been increased by $24 million.

Q. DOES MR. GALBRAITH REQUEST THAT IDAHO POWER PROVIDE HOURLY RESULTS OF PROJECTED SYSTEM OPERATIONS IN

ITS NEXT RATE FILING?

A. Yes, and if such hourly information can be accessed and provided, the sort of daily load duration analysis that I am discussing could be done by Staff.

Idaho Power's Requested $47.7 Million in NVPC
<u>Is Consistent with Previous NVPC and IPUC Levels</u>

Q. IS THE $47.7 MILLION LEVEL OF NET VARIABLE POWER COSTS REQUESTED IN THIS CASE GENERALLY IN LINE WITH THOSE IN RATES IN OREGON AT THE PRESENT TIME?

A. Yes. In the 1993 general rate case in Oregon, Idaho Power used its Secondary Transactions Model in estimating its net variable power costs. It is my understanding that this model estimated, and the Oregon Commission authorized approximately $45 million in net power costs in that case. And, although there is no reason to expect that net power costs will remain relatively constant, it is nevertheless a prudent check to note that the previous model estimated net power costs in line with those estimated by the AURORA model in this case.

Q. ARE THE NET POWER COSTS REQUESTED BY IDAHO POWER IN THIS CASE THE SAME AS ADOPTED RECENTLY BY THE IDAHO PUBLIC UTILITIES COMMISSION FOR THE STATE OF IDAHO?

A. Yes, on a jurisdictional-adjusted basis, of course. In that Idaho case, the Idaho Staff reviewed the net power costs estimated by AURORA to be reasonable, if not low. Other parties were virtually silent.

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED STAFF WITNESS GALBRAITH'S CONCERNS WITH THE OPERATION OF AND ASSUMPTIONS FOR THE AURORA MODEL. IN YOUR OPINION, SHOULD THE COMMISSION ATTEMPT TO DEAL CONCLUSIVELY WITH THE PROPER ASSUMPTIONS, INPUTS AND MODELING TECHNIQUES TO BE USED IN THESE PROCEEDINGS FOR DETERMINING NET POWER COSTS?

A. No. As I mentioned on page 4 of my testimony, I suggest that any detailed review of the AURORA or other models, as well as the key inputs and assumptions be conducted outside of a general rate case. All parties and stakeholders would benefit from an independent workshop or other formal process that is not burdened with the press of other general rate case obligations.

The Company has indicated a willingness to work cooperatively with Staff and other parties and stakeholders to increase the level of understanding and comfort with the AURORA model.

Q. How do you recommend that this Commission resolve this net power cost issue in these proceedings?

A. I recommend that the Commission recognize the circumstances surrounding the net power cost issue in this case, and order the type of investigative forum I discuss above. The circumstances I refer to are:

1. The long lapse of time between Idaho Power general rate cases in Oregon.

2. The comparability of net power costs requested by

Idaho Power in this case, $47.7 million, with the similar level presently in rates.

3. The benefits of not ruling determinatively on the proper methods of modeling until Staff and other parties have a better opportunity to review these matters.

4. The obvious predicament that would be created by ordering a greatly reduced level of net power costs when facing the near certain event of extraordinarily low water conditions again this year.

I conclude that adopting the $47.7 million figure for net power costs in this case and undertaking a more thorough review in the near term in is the public interest.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 301

DENNIS J. PESEAU

STATEMENT OF OCCUPATIONAL AND
EDUCATIONAL HISTORY AND QUALIFICATIONS
DENNIS E. PESEAU

Dr. Peseau has conducted economic and financial studies for regulated industries for the past thirty-three years. In 1972, he was employed by Southern California Edison Company as Associate Economic Analyst, and later as Economic Analyst. His responsibilities included review of financial testimony, incremental cost studies, rate design, econometric estimation of demand elasticities and various areas in the field of energy and economic growth. Also, he was asked by Edison Electrical Institute to study and evaluate several prominent energy models as part of the Ad Hoc Committee on Economic Growth and Energy Pricing.

From 1974 to 1978, Dr. Peseau was employed by the Public Utility Commissioner of Oregon as Senior Economist. There he conducted a number of economic and financial studies and prepared testimony pertaining to public utilities.

In 1978 Dr. Peseau established the Northwest office of Zinder Companies, Inc. He has since submitted testimony on economic and financial matters before state regulatory commissions in Alaska, California, Idaho, Maryland, Minnesota, Montana, Nevada, Washington, Wyoming, the District of Columbia, the Bonneville Power Administration and the Public Utilities Board of Alberta on over one hundred occasions. He has conducted marginal cost and rate design studies and prepared testimony on these matters in Alaska, California, Idaho, Maryland, Minnesota, Nevada, Oregon, Washington and in the District of Columbia. He has also conducted cost and rate studies regarding PURPA issues in the states of Alaska, California, Idaho, Montana, Nevada, New York, Washington, and Washington, D.C.

Dr. Peseau holds the B.A., M.A. and Ph.D. degrees in economics.

He has co-authored a book in the field of industrial organization entitled, Size, Profits and Executive Compensation in the Large Corporation, which devotes a chapter to regulated industries.

Dr. Peseau has published articles in the following professional journals: Review of Economics and Statistics, Atlantic Economic Journal, Journal of Financial Management, and Journal of Regional Science. His articles have been read before the Econometric Society, the Western Economic Association, the Financial Management Association, the Regional Science Association and universities in the United Kingdom as well as in the United States.

He has guest lectured on marginal costing methods in seminars in New Jersey and California for the Center of Professional Advancement. He has also guest lectured on cost of capital for the public utility industry before the Pacific Coast Gas and Electric Association, and for the Executive Seminar at the Colgate Darden Graduate School of Business, University of Virginia.

Dr. Peseau and his firm have participated with and been members of the American Economic Association, the American Financial Association, the Western Economic Association, the Atlantic Economic Association and the Financial Management Association. He was formerly a member of the Staff Subcommittee on Economics of the National Association of Regulatory Utility Commissioners.

Dr. Peseau has been President of Utility Resources, Inc. since 1985.

BEFORE THE

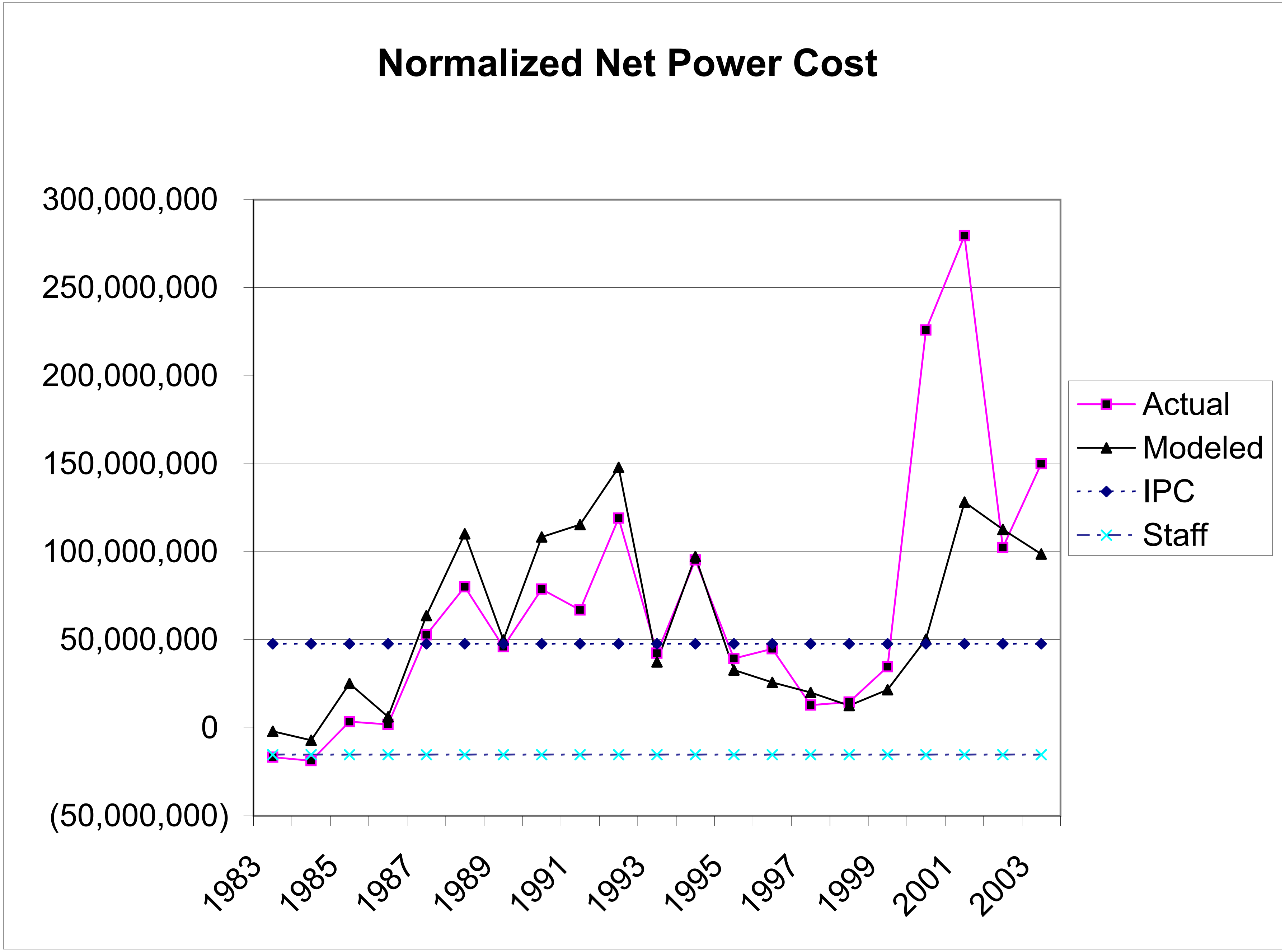
OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 302

DENNIS J. PESEAU


Normalized Net Power Cost
300,000,000
250,000,000
200,000,000
150,000,000
100,000,000
50,000,000
0
(50,000,000)
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
Actual
Modeled
IPC
Staff

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 303

DENNIS J. PESEAU

Idaho Power/303
Peseau/1

EXHIBIT NO. 13
CASE NO. UE___
G. SAID, IPCO
PAGE 1 OF 77

POWER SUPPLY EXPENSES NORMALIZED INCLUDING KNOWN AND MEASURABLE POWER SUPPLY ADJUSTMENTS

AVERAGE

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
1 Hydroelectric Generation (mwh)	796,221.1	832,943.3	817,100.1	850,869.7	859,088.5	858,151.1	759,935.6	726,751.7	675,876.1	541,432.4	456,092.1	662,560.9	8,837,022.5
2 Bridger													
3 Energy (mwh)	438,772.7	378,579.5	442,661.3	391,177.1	327,570.9	326,888.8	455,772.4	455,868.7	441,499.2	456,599.6	441,577.7	456,158.0	5,013,126.0
4 Cost ($ x 1000)	$5,593.3	$4,826.0	$5,642.8	$4,986.5	$4,175.7	$4,167.0	$5,810.0	$5,811.2	$5,628.0	$5,820.5	$5,629.0	$5,814.9	$63,904.9
5 Boardman													
6 Energy (mwh)	35,892.5	31,118.0	36,441.9	32,832.6	29,961.8	0.0	38,327.3	38,725.3	37,546.0	38,791.7	37,544.3	38,754.2	395,935.6
7 Cost ($ x 1000)	$475.4	$412.2	$482.7	$434.9	$396.9	$0.0	$507.7	$513.0	$497.4	$513.9	$497.3	$513.4	$5,244.7
8 Valmy													
9 Energy (mwh)	162,669.0	145,085.8	78,685.9	114,741.2	151,563.5	148,155.1	163,064.5	163,062.4	157,894.3	162,805.5	157,745.1	163,173.8	1,768,646.1
10 Cost ($ x 1000)	$2,391.3	$2,132.8	$1,156.7	$1,686.7	$2,228.0	$2,177.9	$2,397.1	$2,397.1	$2,321.1	$2,393.3	$2,318.9	$2,398.7	$25,999.8
11 Danskin													
12 Energy (mwh)	10.1	13.8	35.6	8.5	137.6	238.7	149.3	166.9	11.0	5.7	7.0	20.3	804.6
13 Cost ($ x 1000)	$0.5	$0.7	$1.4	$0.4	$6.6	$11.3	$7.6	$8.0	$0.4	$0.3	$0.3	$0.8	$38.1
14 Fixed Capacity Charge - Gas Transportation ($ x 1000)	$272.0	$256.8	$272.0	$264.4	$272.0	$264.4	$272.0	$272.0	$264.4	$272.0	$264.4	$272.0	$3,218.4
15 Total Cost	$272.5	$257.5	$273.4	$264.8	$278.6	$275.7	$279.6	$280.0	$264.8	$272.3	$264.7	$272.8	$3,256.5
	36.3	36.6	36.53	28.7	36.1	37.7	40.8	42.3	38.8	35.0	30.8	31.9	31.8
16 Purchased Power (Excluding CSPP)													
17 Market Energy (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	40,600.1	44,999.7	31,717.5	12,398.6	1,019.0	19,820.4	25,362.5	210,815.2
18 Contract Energy (mwh)	0.0	0.0	0.0	0.0	0.0	32,400.0	33,480.0	33,480.0	0.0	0.0	0.0	0.0	99,360.0
19 Total Energy Excl. CSPP (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	73,000.1	78,479.7	65,197.5	12,398.6	1,019.0	19,820.4	25,362.5	310,175.2
20 Market Cost ($ x 1000)	$397.9	$88.7	$77.7	$28.0	$664.1	$1,531.0	$1,835.1	$1,342.9	$480.8	$35.7	$610.9	$884.1	$7,976.9
21 Contract Cost ($ x 1000)	$0.0	$0.0	$0.0	$0.0	$0.0	$1,400.0	$1,500.0	$1,500.0	$0.0	$0.0	$0.0	$0.0	$4,400.0
22 Total Cost Excl. CSPP ($ x 1000)	$397.9	$88.7	$77.7	$28.0	$664.1	$2,931.0	$3,335.1	$2,842.9	$480.8	$35.7	$610.9	$884.1	$12,376.9
23 Surplus Sales													
24 Energy (mwh)	275,833.0	393,058.0	386,996.0	477,141.2	339,313.2	244,417.9	105,904.1	123,223.1	229,492.0	215,052.0	71,826.3	162,439.0	3,024,695.8
25 Revenue Including Transmission Costs ($ x 1000)	$6,087.5	$8,074.9	$8,461.9	$9,664.7	$6,906.1	$4,803.4	$2,491.3	$3,494.2	$5,931.8	$5,197.5	$1,486.5	$3,519.7	$66,119.4
26 Transmission Costs ($ x 1000)	$275.8	$393.1	$387.0	$477.1	$339.3	$244.4	$105.9	$123.2	$229.5	$215.1	$71.8	$162.4	$3,024.7
27 Revenue Excluding Transmission Costs ($ x 1000)	$5,811.6	$7,681.8	$8,074.9	$9,187.5	$6,566.8	$4,558.9	$2,385.4	$3,371.0	$5,702.3	$4,982.5	$1,414.7	$3,357.3	$63,094.8
28 Net Power Supply Costs ($ x 1000)	$3,318.8	$35.3	($441.5)	($1,786.6)	$1,176.5	$4,992.8	$9,944.2	$8,473.1	$3,489.8	$4,053.1	$7,906.2	$6,526.5	$47,688.1
	22.1	20.5	21.9	20.3	20.35	19.7	22.5	28.4	25.9	23.2	20.7	21.7	20.9 ave.

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 304

DENNIS J. PESEAU

Staff Adjustments to Idaho Power Exhibit No. 13
Power Supply Expenses Normalized Using Idaho Power's Forward Price Curves from April 30, 2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
1 Hydroelectric Generation (mwh)	796,221.1	832,943.3	817,100.1	850,869.7	859,088.5	858,151.1	759,935.6	726,751.7	675,876.1	541,432.4	456,092.1	662,560.9	8,837,022.5
2 Bridger													
3 Energy (mwh)	438,772.7	378,579.5	442,661.3	391,177.1	327,570.9	326,888.8	455,772.4	455,868.7	441,499.2	456,599.6	441,577.7	456,158.0	5,013,126.0
4 Cost ($ x 1000)	$5,593.3	$4,826.0	$5,642.8	$4,986.5	$4,175.7	$4,167.0	$5,810.0	$5,811.2	$5,628.0	$5,820.5	$5,629.0	$5,814.9	$63,904.9
5 Boardman													
6 Energy (mwh)	35,892.5	31,118.0	36,441.9	32,832.6	29,961.8	0.0	38,327.3	38,725.3	37,546.0	38,791.7	37,544.3	38,754.2	395,935.6
7 Cost ($ x 1000)	$475.4	$412.2	$482.7	$434.9	$396.9	$0.0	$507.7	$513.0	$497.4	$513.9	$497.3	$513.4	$5,244.7
8 Valmy													
9 Energy (mwh)	162,669.0	145,085.8	78,685.9	114,741.2	151,563.5	148,155.1	163,064.5	163,062.4	157,894.3	162,805.5	157,745.1	163,173.8	1,768,646.1
10 Cost ($ x 1000)	$2,391.3	$2,132.8	$1,156.7	$1,686.7	$2,228.0	$2,177.9	$2,397.1	$2,397.1	$2,321.1	$2,393.3	$2,318.9	$2,398.7	$25,999.8
11 Danskin													
12 Energy (mwh)	10.1	13.8	35.6	8.5	137.6	238.7	149.3	166.9	11.0	5.7	7.0	20.3	804.6
13 Cost ($ x 1000)	$0.5	$0.7	$1.4	$0.4	$6.6	$11.3	$7.6	$8.0	$0.4	$0.3	$0.3	$0.8	$38.1
14 Fixed Capacity Charge - Gas Transportation ($ x 1000)	$272.0	$256.8	$272.0	$264.4	$272.0	$264.4	$272.0	$272.0	$264.4	$272.0	$264.4	$272.0	$3,218.4
15 Total Cost	$272.5	$257.5	$273.4	$264.8	$278.6	$275.7	$279.6	$280.0	$264.8	$272.3	$264.7	$272.8	$3,256.5
16 Forward Price Curve (Flat $/MWh)	**$52.65**	**$52.13**	**$51.61**	**$32.12**	**$30.86**	**$31.49**	**$48.46**	**$50.77**	**$47.08**	**$41.54**	**$43.84**	**$46.16**	**$44.06**
17 Purchased Power (Excluding CSPP)													
18 Market Energy (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	40,600.1	44,999.7	31,717.5	12,398.6	1,019.0	19,820.4	25,362.5	210,815.2
19 Contract Energy (mwh)	0.0	0.0	0.0	0.0	0.0	32,400.0	33,480.0	33,480.0	0.0	0.0	0.0	0.0	99,360.0
20 Total Energy Excl. CSPP (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	73,000.1	78,479.7	65,197.5	12,398.6	1,019.0	19,820.4	25,362.5	310,175.2
21 Market Cost ($ x 1000)	**$578.0**	**$126.4**	**$109.8**	**$31.4**	**$567.5**	**$1,278.5**	**$2,180.8**	**$1,610.3**	**$583.7**	**$42.3**	**$869.0**	**$1,170.6**	**$9,148.4**
22 Contract Cost ($ x 1000)	$0.0	$0.0	$0.0	$0.0	$0.0	$1,400.0	$1,500.0	$1,500.0	$0.0	$0.0	$0.0	$0.0	$4,400.0
23 Total Cost Excl. CSPP ($ x 1000)	**$578.0**	**$126.4**	**$109.8**	**$31.4**	**$567.5**	**$2,678.5**	**$3,680.8**	**$3,110.3**	**$583.7**	**$42.3**	**$869.0**	**$1,170.6**	**$13,548.4**
24 Surplus Sales													
25 Energy (mwh)	275,833.0	393,058.0	386,996.0	477,141.2	339,313.2	244,417.9	105,904.1	123,223.1	229,492.0	215,052.0	71,826.3	162,439.0	$3,024,695.7
26 Revenue Including Transmission Costs ($ x 1000)	**$14,523.3**	**$20,491.1**	**$19,973.9**	**$15,325.7**	**$10,471.3**	**$7,696.7**	**$5,132.5**	**$6,256.2**	**$10,803.7**	**$8,932.9**	**$3,149.0**	**$7,497.5**	**$130,253.7**
27 Transmission Costs ($ x 1000)	$275.8	$393.1	$387.0	$477.1	$339.3	$244.4	$105.9	$123.2	$229.5	$215.1	$71.8	$162.4	$3,024.7
28 Revenue Excluding Transmission Costs ($ x 1000)	**$14,247.4**	**$20,098.0**	**$19,586.9**	**$14,848.5**	**$10,132.0**	**$7,452.3**	**$5,026.6**	**$6,133.0**	**$10,574.3**	**$8,717.8**	**$3,077.2**	**$7,335.0**	**$127,229.0**
29 Net Power Supply Costs ($ x 1000)	**($4,936.9)**	**($12,343.2)**	**($11,921.5)**	**($7,444.2)**	**($2,485.2)**	**$1,846.9**	**$7,648.6**	**$5,978.6**	**($1,279.3)**	**$324.4**	**$6,501.8**	**$2,835.3**	**-$15,274.6**
30 Idaho Power Exhibit 13 Net Power Supply Costs ($ x 1000)	$3,318.8	$35.3	($441.5)	($1,786.6)	$1,176.5	$4,992.8	$9,944.2	$8,473.1	$3,489.8	$4,053.1	$7,906.2	$6,526.5	$47,688.1
31 Total Staff Adjustment ($ x 1000)	($8,255.7)	($12,378.5)	($11,479.9)	($5,657.6)	($3,661.7)	($3,145.9)	($2,295.5)	($2,494.5)	($4,769.1)	($3,728.7)	($1,404.4)	($3,691.2)	($62,962.8)

52.65

52.65

UE 167
STAFF EXHIBIT 202
GALBRAITH/27

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 306

DENNIS J. PESEAU

Idaho Power Company
Annual Hydro Production Autocorrelation Analysis

	Current	*Lag 1*	*Lag 2*	*Lag 3*	*Lag 4*	*Lag 5*	*Lag 6*	*Lag 7*	*Lag 8*	*Lag 9*	*Lag 10*
Current	1										
Lag 1	0.508840967	1									
Lag 2	0.337991315	0.498615211	1								
Lag 3	0.050399915	0.333037766	0.482153503	1							
Lag 4	-0.05133704	0.07740125	0.34480558	0.510890932	1						
Lag 5	-0.206486986	-0.01308274	0.112567597	0.3969669	0.530606918	1					
Lag 6	-0.19949683	-0.165909	0.027850562	0.170893924	0.419332879	0.531510569	1				
Lag 7	-0.082949902	-0.1346672	-0.108020635	0.115560381	0.220209402	0.42606925	0.527742198	1			
Lag 8	-0.120531857	-0.041463664	-0.097968245	-0.051796246	0.14742531	0.225529325	0.424696164	0.530198693	1		
Lag 9	-0.031142816	-0.10428929	-0.028243139	-0.0760524	-0.033601993	0.152782787	0.229034251	0.430307584	0.53362898	1	
Lag 10	0.045321324	-0.071545949	-0.149416726	-0.08317724	-0.097369083	-0.026921942	0.17184611	0.247200592	0.445463733	0.539580778	1

BEFORE THE

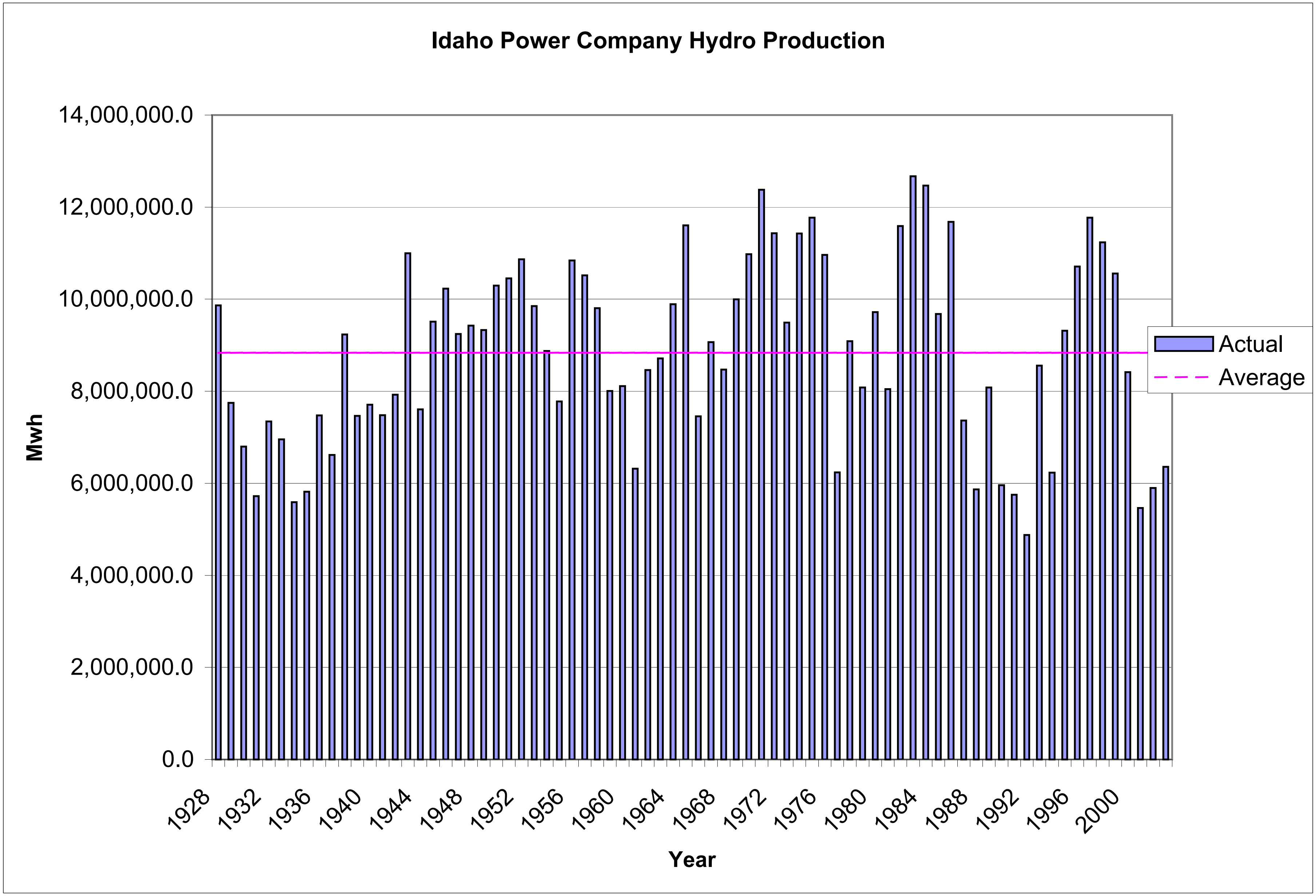
OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 307

DENNIS J. PESEAU


Idaho Power Company Hydro Production
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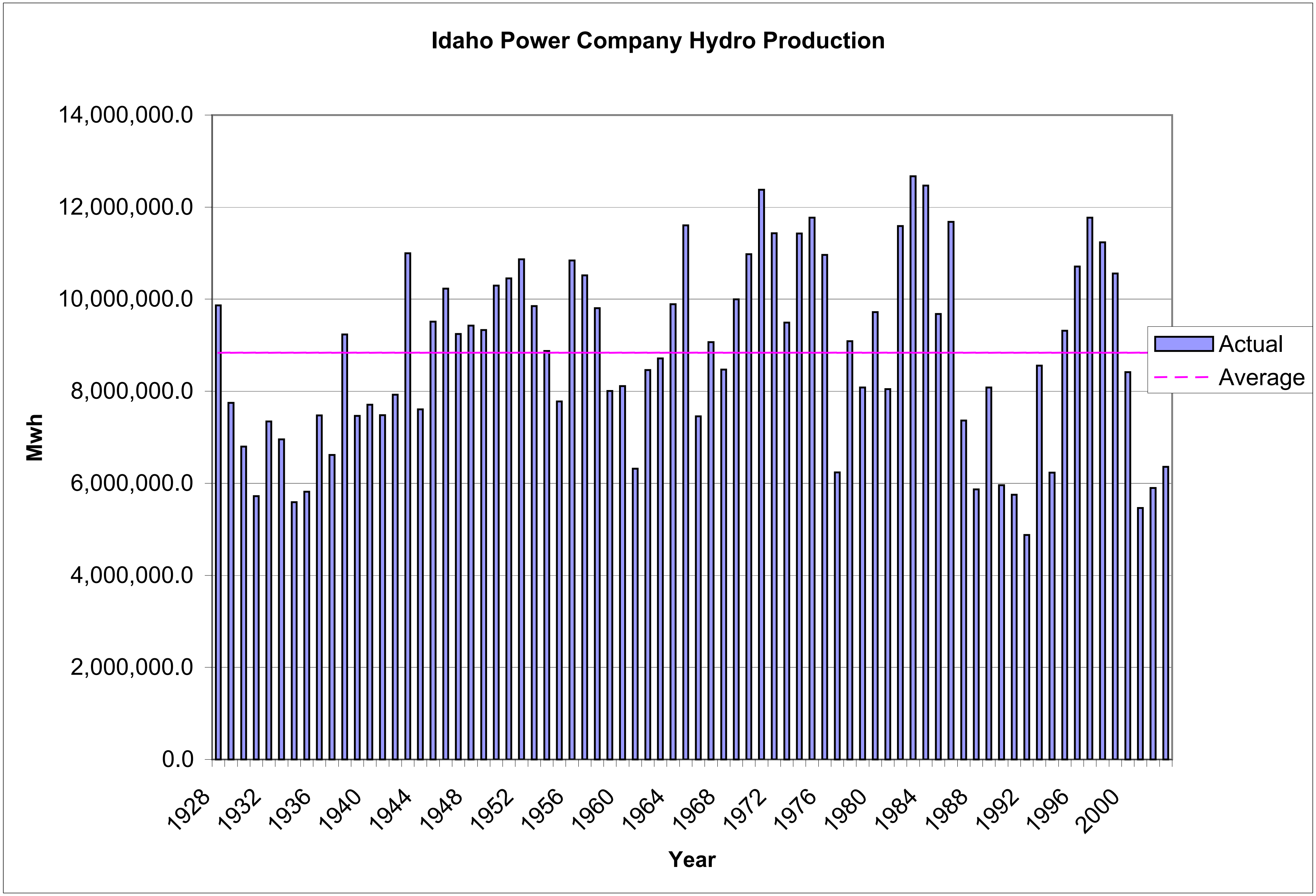
12,000,000.0
10,000,000.0
8,000,000.0
6,000,000.0
4,000,000.0
2,000,000.0
0.0
Mwh
1928
1932
1936
1940
1944
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
2000
Year
Actual
Average


Idaho Power Company Hydro Production
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12,000,000.0
10,000,000.0
8,000,000.0
6,000,000.0
4,000,000.0
2,000,000.0
0.0
Mwh
1928
1932
1936
1940
1944
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
2000
Year
Actual
Average

BEFORE THE

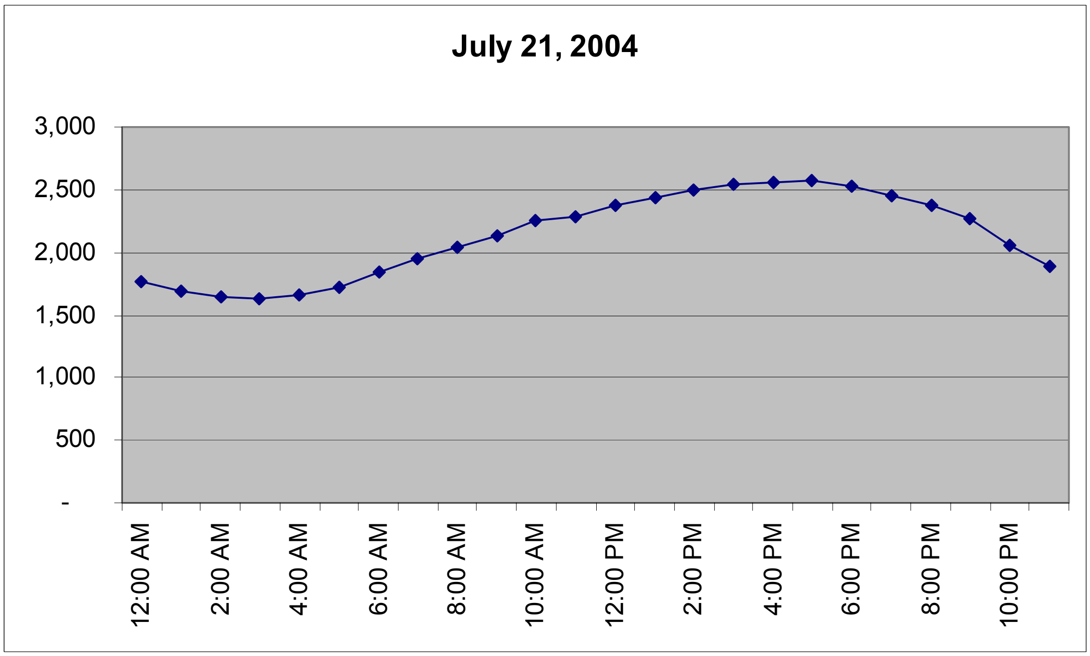
OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 308

DENNIS J. PESEAU


July 21, 2004
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO CUSTOMERS IN THE	)
STATE OF OREGON	)
	)

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

PETE PENGILLY

Q. Please state your name, address, and present occupation.

A. My name is Pete Pengilly. I am a Senior Analyst in the Pricing and Regulatory Services Department at Idaho Power Company. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same Pete Pengilly that previously presented direct testimony in this case?

A. Yes, I am.

Q. Have you reviewed the pre-filed direct testimony of the Citizen's Utility Board of Oregon (CUB) and the Oregon Industrial Customers of Idaho Power (OICIP) in this case?

A. Yes, I have.

Q. Q. What is the scope of your rebuttal testimony?

A. My testimony will address issues raised by CUB regarding seasonal rates for residential customers and by OICIP regarding time-of-use rates for individual industrial customers taking service under Schedule 19.

Q. CUB recommends that the Commission maintain the current flat annual rate design for residential customers rather than the seasonal rate design proposed by the Company since the residential class as a whole has its highest demand in the winter. Please comment on CUB's recommendation.

A. The Company's rate design proposal is driven by system load characteristics and system resource availability rather than specific customer class load characteristics. Unlike some of the other utilities in the Northwest, Idaho Power is a summer-peaking utility. As is evidenced in the

Company’s 2004 Integrated Resource Plan, which is currently pending before the Commission in Docket No. LC-36, the Company’s need for additional resources is driven primarily by the peak summer usage during summer resource scarcity and only secondarily by peak winter usage. Loads on the Company’s system, both in terms of peak demand and energy usage, are greatest during the months of June, July, and August. By implementing seasonal rates, the Company is striving to signal those customers, whose usage contributes to the summer peak, that consumption during the summer months is more costly. This price signal should provide an incentive for these customers to conserve.

Q. Do you believe that the Company’s seasonal rate proposal for residential customers will lessen the conservation incentive for customers who use electric space heat during the winter?

A. No. Under the Company’s proposal, residential customers would see a ten percent increase in their energy rate during the non-summer months for the first 300 kWh used and a fifteen percent increase of all electricity over 300 kWh used. I believe the customer that uses electric space heat will see this as not only a higher rate, but also experience an increase in non-summer bills. The block rates and the rate increase should provide an incentive for a decrease in consumption by customers who use electric space heat.

Q. Do you have any evidence to suggest that residential customers will find the seasonal rates proposed by the Company confusing as implied by CUB?

A. No, I do not. The residential seasonal rate design proposed by the Company is almost identical to the residential seasonal rate design approved by the Idaho Public Utilities Commission in the Company's recent Idaho general rate case. The Company has not had any indication from our Idaho customers that the seasonal rates have caused confusion or an inability to understand their bills.

Q. The OICIP states in its testimony that the purpose of time-of-use rates is to cause customers to curtail power consumption during the relatively expensive on-peak periods. Do you agree with this statement?

A. No. While a change in customers' consumptive patterns may result from time-of-use pricing, time-of-use rates are primarily intended to more closely match the rate for energy that customers pay with the Company's cost of providing that energy during different periods of the day and across the different seasons. By better matching the customers' rate for energy with the Company's cost of energy, each customer pays a price appropriately reflective of the cost of the energy that they consume.

The intent of Idaho Power's Time-of-Use rate design is not to penalize those industrial customers who do not change their usage patterns, but to give them a financial incentive to do so. Idaho Power does not believe that a change in usage patterns will necessarily occur in the short term. Over time, however, as customers revise business practices or replace equipment, they can and will respond to price signals.

Q. The OICIP contends that the results of the "dummy" billing that took place in Idaho from June 1 to December 1, following approval of time-of-use rates for Idaho Schedule 19 industrial customers, clearly show that the industrial customers have not changed their power consumption patterns as a result of time-of-use rates. Do you agree with this conclusion?

A. No. The “dummy” bills did not send any actual price signals. The “dummy” bills merely provided customers taking service under Idaho’s Schedule 19 with a comparison of what their bills would have been had they actually been charged the time-of-use rates rather than the flat seasonal rates that were actually in effect. Since customers were not actually charged time-of-use rates during this six-month period, I do not believe it can be concluded that time-of-use rates would not influence customers’ usage patterns.

Q. The OICIP quotes a response provided by the Company to an OICIP production request that states that time-of-use rates had a negligible effect on billings for Schedule 19 customers in Idaho compared to the flat rates for the six-month phase-in period. Would you please explain why this negligible effect occurred?

A. First, I must reiterate how the time-of-use prices proposed by the Company were calculated. The first step in the process was to develop flat rates that varied by season, both summer and non-summer. The second step in the process was to convert the flat seasonal rates into seasonal time-of-use rates. The Company’s analysis for its Idaho customers taking service under Schedule 19 showed that the implementation of seasonal rates had a greater effect on customers’ overall bills than did the implementation of time-of-use rates. This effect resulted from the fact that, although Schedule 19 customers, in general, tend to be high load factor and consistent-use customers, their usage does vary by season. Charging industrial customers' rates that vary by season has a greater impact than do rates that vary by time-of-day. When the effect of seasonal time-of-day prices is compared to the effect of seasonal flat rates, as was done with the "dummy" bills, the overall difference tends to be minor.

Q. Does this result suggest that time-of-use pricing is inappropriate for Schedule 19 customers?

A. No. Time-of-use pricing better matches the customer's rate for energy to the Company's cost of energy, thereby providing a clearer price signal to customers regarding the energy costs associated with their usage pattern. This presents an opportunity for customers to reduce their bills by shifting their energy consumption to less costly time periods.

Q. The OICIP states in its testimony that the Company's Time-of-Use rate design is very complex. They contend that it requires the customer to spend a lot of time in order to clearly understand the impact of the proposed pricing. Do you agree with this statement?

A. No. As I have stated, the rate is designed to be non-punitive if the customer does not choose to change their usage pattern. It merely provides them an opportunity for savings. In Idaho, the Company has seen no evidence of industrial customers not understanding the rates. Time-of-Use rates have been in effect for industrial customers elsewhere for many years. I believe many of Idaho Power's industrial customers are familiar with them through national industrial organizations and by having facilities in other regions where time-of-use rates are already in place.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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TO ELECTRIC CUSTOMERS IN THE STATE)
OF OREGON.)
)

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

KEITH J. KOLAR

Q. Please state your name, address, and present occupation.

A. My name is Keith J. Kolar. My business address is 1550 South Main Street, Payette, Idaho. I am Regional Operations Manager of Delivery in Payette/Canyon Region for Idaho Power Company.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Have you reviewed the testimony and exhibits of Dr. Reading, the witness for Oregon Industrial Customers of Idaho Power ("OICIP"), specifically relating to the service quality in Idaho Power's Oregon jurisdiction?

A. Yes.

Q. Please provide some perspective on Idaho Power's service quality in its Oregon jurisdiction.

A. Idaho Power has 13 Large Power Service customers in the Oregon service territory. These customers are served under Tariff Schedule 19 and are frequently referred to as Schedule 19 customers. Of the 13 customers, eleven are served from distribution feeders that serve other customers, one (Heinz) is served on a dedicated feeder, and one customer is served from transmission voltage. From January 2000 through January 2005, the Company compiled information on the number of momentary outages (those lasting less than five minutes), the number of extended outages, and the total hours of outage for Oregon Schedule 19 customers. Exhibit 501 shows the results for those Oregon Schedule 19 customers served through distribution feeders. For this group, the momentary outages totaled 235, the extended outages totaled 83, and the total hours out amounted to 68.28 hours. I view these outage figures as indicative of generally reliable service. Most Schedule 19 customers are supplied on shorter distribution feeders relative to other customers, thus having fewer connections and devices to create problems. It has been my experience that the Schedule 19 reliability in Oregon is very similar to that in Idaho.

Q. Did you review the outages at the Heinz food processing plant that Dr. Reading mentions in his testimony?

A. Yes. The Heinz facility is served on a dedicated distribution feeder. This means that it is the only customer served from a distribution line. In the last five years, there were 16 outages at Heinz. The total duration of these outages was 18 hours, 23 minutes, and 20 seconds. The causes for the outages ranged from loss of supply, customer equipment, planned outages, adverse weather, foreign objects, and some of unknown origin. During the five year time period, customer equipment was the leading cause of the outages. Exhibit 502 details this information.

Q. Can you provide some budgetary perspective on Idaho Power's efforts to maintain distribution reliability in Oregon?

A. Yes. Each year Idaho Power budgets and schedules for Oregon line patrol, Oregon capital re-construction, overhead/underground re-construction, and distribution feeder maintenance to improve the overall reliability. During 2003 - 2004, Idaho Power expended more than $2,000,000 in reliability-related items in Oregon. Exhibit 503 is a summary of dollars spent on the 60 distribution feeders for the years 2003 and 2004.

Q. Does this complete your testimony?

A. Yes, it does.

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 501

KEITH J. KOLAR

Oregon Outage Information
Distribution Schedule 19 Customers (Excluding Heinz)

IDAHO POWER COMPANY
BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON
OREGON OUTAGE INFORMATION
DISTRIBUTION SCHEDULE 19 CUSTOMERS (EXCLUDING HEINZ)
FIVE YEAR TOTALS
(1/1/200 TO 1/1/2005)

Schedule 19 Customers

	Feeder	Momentary Outages <5 mins	Extended Outages	Total Hours
1	CARO13	22	8	3.43
2	NYSA14	4	4	2.98
3	ONTO20	15	8	7.1
4	CARO13	22	8	3.43
5	NYSA11	5	5	3.63
6	OIDA11	5	5	2.23
7	ONTO24	18	11	11.17
8	ONTO25	5	11	10.44
9	ONTO20	15	8	7.1
10	HOPE11	108	11	13.2
11	MRBT41	16	4	3.57
	5 Year Totals	**235**	**83**	**68.28**
	Avg/year/customer	**4.27**	**1.51**	**1.24**

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 502

KEITH J. KOLAR

Heinz Outage Information

IDAHO POWER COMPANY
BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON
HEINZ OUTAGE INFORMATION
5 YEAR TOTALS
(1/1/2000 TO 1/1/2005)

OUTAGE	DEVICE	OFF DATE	OFF TIME	ON DATE	ON TIME	DURATION	LOSS OF	CUSTOMER	PLANNED	ADVERSE	FOREIGN	UNKNOWN	COMMENTS
NUM						HH:MM:SS	SUPPLY	EQUIPMENT	MAINTENANCE	WEATHER	OBJECT		OIDA-012, DEDICATED PLANT FEEDER
1	STN	1/27/1998	17:34:00	1/27/1998	17:37:00	3:00	3:00						TRANSMISSION LINE
2	BKR	1/29/1998	15:10:00	1/29/1998	16:54:00	1:44:00		1:44:00					OUTAGE FOR OIDA
3	F3	6/11/1998	5:13:00	6/11/1998	6:41:00	1:28:00			1:28:00				PREARRANGED OUTAGE
4	BKR	3/20/1999	10:22:00	3/20/1999	10:22:00	0:00:05						0:00:05	APPARENT TRIP CLOSE
5	F4	2/6/2000	20:13:00	2/6/2000	21:24:00	1:11:00			1:11:00				TRANSFORMER CHANGE (DIST)
6	BKR	6/23/2000	7:29:00	6/23/2000	8:12:00	0:43:00	0:43:00						LOSS OF SUPPLY
7	STN	9/5/2000	22:17:00	9/5/2000	22:17:00	0:00:05	0:00:05						TRANSMISSION, APPARENT TRIP CLOSE
8	BKR	7/4/2001	13:27:00	7/4/2001	13:27:00	0:00:05					0:00:05		FIRE BEHIND OIDA FOODS AT RR
9	F2	8/9/2001	10:18:00	8/9/2001	13:00:00	2:42:00		2:42:00					CUSTOMER REQUESTED OUTAGE
10	BKR	11/4/2001	15:38:00	11/4/2001	16:20:00	0:42:00						0:42:00	NO CAUSE STATED
11	BKR	6/22/2002	7:55:00	6/22/2002	8:16:00	0:21:00				0:21:00			NO CAUSE STATED
12	BKR	7/8/2002	12:32:00	7/8/2002	12:41:00	0:08:00					0:08:00		BALLOON IN LINE
13A	F18	7/31/2002	9:28:00	7/31/2002	9:39:00	0:11:00			0:11:00				REMOVING LINE
13B	F12	7/31/2002	9:36:00	7/31/2002	9:39:00	0:03:00			0:03:00				PLANNED OUTAGE
13C	X6	7/31/2002	9:39:00	7/31/2002	11:21:00	1:42:00			1:42:00				FOR THESE
13D	F12	7/31/2002	11:21:00	7/31/2000	11:24:00	0:03:00			0:03:00				FIVE ITEMS
13E	F18	7/31/2002	11:21:00	7/31/2002	11:26:00	0:05:00			0:05:00				
14	BKR	4/26/2003	8:18:00	4/26/2003	8:18:00	0:00:05	0:00:05						NO CAUSE STATED
15	F20	9/21/2003	12:00:00	9/21/2003	16:00:00	4:00:00		4:00:00					FIRE IN CUST EQUIPMENT
16	BKR	10/23/2003	14:38:00	10/23/2003	14:58:00	0:20:00	0:20:00						LOSS OF TRANSMISSION
	TIME PERIOD 1998 THRU 2004					18:23:20	4:03:10	8:26:00	4:43:00	0:21:00	0:08:05	0:42:05	TOTAL OUTAGE TIME
						16	5	3	3	1	2	2	NUMBER OF EVENTS

BEFORE THE

OREGON PUBLIC UTILITIES COMMISSION

CASE NO. UE 167

IDAHO POWER COMPANY

EXHIBIT NO. 503

KEITH J. KOLAR

Summary of 2003-2004 Maintenance
and Capital Expenditures

Summary of 2003..2004 Maintenance and Capital Expenditures	
Payette and Canyon	
Payette Region	
2003 Oregon Patrol	119,601.10
2004 Oregon Patrol	432,567.70
2003/2004 Oregon Patrol Capital Re-Construction WO's	75,192.68
Overhead/Underground Cap. Re-Construction By Oregon Team	648,683.49
2003 Feeder Maintenance Actuals	314,900.81
2004 Feeder Maintenance Actuals	328,422.87
Payette Total	1,919,368.65
Canyon Region	
2003 Oregon Patrol/Feeder Maintenance	24,925.46
2003/2004 Oregon Patrol Capital Re-Construction WO's	5,648.70
Overhead Re-Construction in Oregon by South Canyon TM	10,568.53
2004 Oregon Patrol/Feeder Maintenance	53,408.38
Canyon Total	94,551.07
Oregon Grand Total	2,013,919.72

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OF OREGON.)
)

IDAHO POWER COMPANY

REBUTTAL TESTIMONY

OF

JOHN R. GALE

Q. Please state your name and business address.

A. My name is John R. Gale and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. Are you the same Mr. Gale that presented direct testimony in this proceeding?

A. Yes.

Q. What issues will you be responding to in your rebuttal testimony?

A. My testimony will address (1) the Company's confirmation and clarification of the settlement between Idaho Power and the Oregon staff discussed in Staff Witness Owings' testimony; (2) the Company's position regarding the Oregon Industrial Customers of Idaho Power ("OICIP") request to explore distributive generation possibilities at industrial sites; (3) the Company's planned expansion of energy efficiency programs into the state of Oregon as discussed in the Citizens Utility Board ("CUB") testimony; and (4) the Company's rate plan for the Oregon service territory and the practical impacts of net power supply costs determinations in light of these plans.

Q. Have you reviewed the testimony and exhibits prepared by Staff Witness Owings?

A. Yes.

Q. Do you agree with the Staff's characterization and calculation of the summary sheet that appears as Staff Exhibit 102?

A. Yes. It is an accurate representation of the settlement agreement reached between the Oregon Staff and Idaho Power Company.

Q. Has the stipulation document been filed with the Commission?

A. It has not yet been filed, but the parties are diligently working on completing the document along with its supporting testimony.

Q. Staff Witness Owings identified two non-revenue requirement issues that have been agreed upon by the parties and are to be included in the settlement stipulation. Those two issues are (1) the allocation of uncollectible expenses as they relate to rate design, and (2) the Company's proposal to add a $20 Service Establishment Charge. Are they any other issues that have been agreed upon between the Company and Staff that Ms. Owings has not addressed?

A. Yes. In addition to the two non-revenue requirement issues identified by Ms. Owings, the Staff and the Company have agreed to accept the Company's rate design as proposed in the Company's filing.

Q. Have you reviewed the testimony and exhibits prepared by OICIP Witness Reading regarding the potential for using customer-owned emergency back-up generators as distributed generation ("DG")?

A. Yes.

Q. What is your response to Witness Reading's suggestion that the "Commission direct its Staff and the Company to cooperate with Holy Rosary Medical Center along with any other emergency generators in the Oregon service territory in an effort to determine the variability (sic) of using these generators to help meet peak load"?

A. The Company is interested in potential DG opportunities that are beneficial to its retail customers. The Company will pursue the DG potential directly with Holy Rosary Medical Center and with any other Oregon customer with DG potential. The Company willingly commits to explore these options without being directed to do so by the Commission. Idaho Power encourages customers that have DG potential to contact the Company directly.

Q. Have you reviewed the testimony and exhibits prepared by CUB Witnesses Jenks and Brown regarding expansion of energy efficiency programs within Idaho Power's Oregon service territory?

A. Yes.

Q. Do you agree with CUB's representation of the agreement in principle between CUB and Idaho Power concerning expansion of energy efficiency programs within Idaho Power's Oregon service territory?

A. Yes. Once the Idaho Commission issues its order on Idaho Power's request to increase it energy efficiency rider charge in Idaho, the Company commits to filing in Oregon for approval of the same type of mechanism and the same level of commitment.

Q. What is the status of the Idaho energy efficiency rider?

A. The matter has been fully submitted to the Idaho Commission and an order is pending.

Q. Has Idaho Power publicly expressed its intent to bring a similar energy efficiency effort to its Oregon service territory as it has in Idaho?

A. Yes. One of the near-term actions described in the Company's 2004 Integrated Resource Plan ("IRP") is filing the energy efficiency rider with the Oregon Commission. The Company has been waiting on the Idaho order before acting in Oregon, so that the programs could be consistent.

Q. Have you reviewed the testimony and exhibits prepared by Staff Witness Galbraith?

A. Yes.

Q. From a policy perspective, what concerns do you have regarding Staff Witness Galbraith's recommendation on the valuation of net power supply expenses?

A. Witness Galbraith's recommendation regarding net power supply expenses accentuates a very real problem for Idaho Power to have an <u>opportunity</u> to adequately recover its revenue requirement (and earn its authorized return) in the Oregon service territory during the time period the rates ordered from this general rate case will be in place.

Q. Please explain why Mr. Galbraith's recommendation is problematic.

A. First, the rates set in this case will only be in place for a short duration compared to Idaho Power's historically long periods between Oregon general rate cases. Second, due to Idaho Power's strong reliance on its hydro-based generation system, it is impossible for any symmetry in power supply expenses around an extreme normalized base to occur during the relevant time period.

Q. Why do you say that the rates will only be in effect for a relatively short period?

A. Idaho Power is implementing a significant ramp-up in capital expenditures over the next five years. These expenditures are in all major asset classifications and are driven by growth in the service territory, resource demands noted in our 2004 IRP, and the costs associated with relicensing our Hells Canyon Complex. With the heavy construction campaign, comes the need for more frequent requests for general rate relief. At this time, Idaho Power is planning on filing general rate cases in both Idaho and Oregon using 2005 as the test year. The cases may be filed simultaneously as early as this fall. Accordingly, it is likely that the rates resulting from this rate case may only be in effect for 12 to 18 months.

Q. What does filing a new general rate case have to do with Idaho Power's ability to recover costs under this case?

A. Because the Company is experiencing another severe drought year in 2005, there is virtual certainty that our net power supply expenses will be much higher than the expenses we proposed in the current rate request. Further, the net power supply expenses in 2006 are also expected to be above the normalized net power supply expenses proposed in this proceeding. So even adoption of the Company's proposal will likely leave Idaho Power significantly under earning in Oregon during the relevant rate period.

Q. Why do you expect net power supply expenses in 2006 to be above normal?

A. Historically, our system has not experienced a bountiful water year following a severely dry year. It takes several years for the hydro system to recover primarily because the reservoirs need to be refilled and base flows have declined with the drought.

Q. Please summarize your concern with Mr. Galbraith's proposal for setting net power supply expenses.

A. In my view, the revenue requirement set in a general rate proceeding should reasonably represent the utility's costs to serve its retail customers during the relevant time period that the resulting rates are in effect. That is not a possibility for Idaho Power even if the Company's proposed normalized net power supply expense proposal is accepted because of the short time between rate cases. Further reductions like the one proposed by Mr. Galbraith only serve to make a bad situation worse.

Q. Does this conclude your testimony?

A. Yes, it does.