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IDAHO PUBLIC
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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVICE.	)))))))))	**CASE NO. IPC-E-03-13**

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

FEBRUARY 20, 2004

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

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of utility applications and customer petitions.

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

A. The first purpose of my testimony is to discuss the methodology and results of Idaho Power's load normalization, and to make a recommendation on whether I believe the Company's results should be accepted. Next, I discuss the Company's power supply modeling and discuss an alternative method that I used to evaluate Idaho Power's results. Finally, I discuss the Danskin project and make a recommendation on whether I believe the project costs should be allowed in rate base.

Load Normalization

Q. What is load normalization?

A. Load normalization is a process to determine whether actual electricity sales were higher or lower than normal as a result of actual weather. Energy use is statistically estimated as a function of weather and non-weather variables.

Q. Why is load normalization important and how does it affect the Company's revenue requirement?

A. Load normalization is important because it establishes the loads that must be met by Idaho Power in a normal year, which in turn are used for jurisdictional separation, normalization of power supply costs, and cost of service. Normalized loads are also used to determine the revenue that the utility would be expected to receive in a normal year.

Q. Please describe the load normalization performed by the Company in this case.

A. Idaho Power used multiple regression analysis to normalize loads. Normalization was performed separately using eleven different regression equations – two that describe Idaho Power's total system residential and commercial sales, two that describe Oregon's residential and commercial sales, five that describe irrigation sales for each of the Company's operating centers, one that describes sales to the City of Weiser, and one that describes sales to Raft River Rural Electric Cooperative, Inc. To explain electricity use, the regression equations utilize weather concepts such as heating, cooling and growing degree-days and precipitation, as well as economic and demographic information such as electricity price, electric space heat saturation, and air conditioning saturation. Once regression equations were developed, normal variable values were entered into the equations to compute normalized loads. These normal loads were then used by the Company in its power supply modeling, jurisdictional allocation and cost of service studies.

Q. Do you agree with the normalized loads proposed by the Company?

A. Yes, I do. The regression equations developed by the Company are very accurate predictors of usage by various customer groups based on historic conditions and consumption levels. The correlation coefficients obtained by the Company that indicate the accuracy of predictions in its analysis are very high. I believe that the methodology used by the Company is appropriate and that the results are reasonable.

Power Supply Modeling

Q. Have you reviewed the power supply modeling performed by the Company as part of this case?

A. Yes, I have.

Q. Do you agree with the normalized power supply costs proposed by the Company?

A. Although I believe the power supply model the Company used in this case could be improved, I conclude that the normalized power supply costs proposed by Idaho Power appear conservative and so Staff does not oppose the Company's proposal. The Company computed a net power supply cost of $49.6 million for the 2003 test year. With known and measurable adjustments, the Company is proposing that a net power supply cost of $47.7 million be adopted in this case. In the Company's last general rate case (Case No. IPC-E-94-5), a normalized net power supply cost of $48 million was accepted.

Q. Why is the Company's normalized net power supply cost nearly the same as it was in Idaho Power's last general rate case?

A. As discussed in Company witness Said's testimony, several factors have caused upward pressure on power supply expenses, while others have caused downward pressure. The net effect of these factors has caused a modest $1.9 million increase in normalized net power supply costs before known and measurable changes. After known and measurable changes, the difference is a $0.3 million decrease from the last rate case.

As described in Mr. Said's direct testimony, factors that have caused upward pressure on power supply costs include higher market prices along with higher seasonal and peak hour loads that must often be met using higher cost resources. Factors that have caused downward pressure on power supply costs include a slight net decrease in annual system load, expiration of FERC jurisdictional contracts, and overall decreases in coal contract prices.

Q. Did you explore or devise an alternative method to evaluate the normalized power supply expenses proposed by the Company.

A. Besides reviewing the Company's determination of normalized power supply expenses using AURORA, I also performed a regression analysis to estimate a range of normal power supply expenses. In the analysis, I chose the following eight independent variables that affect power supply costs:

(a) Brownlee inflow

(b) Installed generation capacity

(c) Electric market price

(d) Unit cost of fuel at Bridger

(e) Unit cost of fuel at Boardman

(f) Unit cost of fuel at Valmy

(g) System firm load

(h) PURPA purchases

I used net power supply cost as the dependent variable in the regression analysis. I used twenty-four years of historical data in the analysis.

Q. What did you hope to accomplish with your regression technique?

A. My goal was simply to generally compare the value proposed by Idaho Power to estimated net power supply cost using other methods.

Q. What did you conclude from your regression analysis?

A. I concluded that the normalized net power supply expenses proposed by Idaho Power are reasonable and are probably low.

Q. Do you recommend that the Commission accept the normalized net power supply costs as proposed by Idaho Power?

A. Yes, I do. However, I also recommend that the Company and Staff monitor the actual net power supply costs in the coming few years to assure actual net power supply expenses properly track water conditions.

Danskin

Q. Please summarize Commission Order No. 28773 (Case No. IPC-E-01-12) concerning the Danskin plant.

A. In Order No. 28773, the Commission authorized Idaho Power to proceed with the construction of the Danskin plant. In doing so, however, the Commission stated:

> We note that the procedure followed in this case has limited the type and extent of review that would otherwise occur in a certificate filing.
>
> The information provided however is insufficient to determine the reasonableness of the related costs. As reflected in Staff comments, it is unknown whether the Mountain Home Station was the least cost alternative. Because the Mountain Home Station was not

ratepayers and its investors that, in the ordinary course of events, prudently incurred costs of construction in bringing the authorized plant on line will later be recognized in the Company's revenue requirement…" at page 20. We then went on to discuss examples of what type of recovery is not guaranteed. That being said, we nevertheless note that implicit in our decision in this case to approve a certificate for construction of the Mountain Home Station is recovery of some reasonable amount as rate base addition. The Company needs to provide the Commission with more information. What other alternatives were considered? What was the Company's forecasted need? The Company expressed concern that we will assess its decision to build based on hindsight and from a perspective of changed market conditions. We assure the Company that the review standard employed by the Commission will be what Company knew or should have known at the time it made its decision to build.

Q. Did Idaho Power provide additional justification for Danskin in its testimony in this case?

A. No.

Q. Why is Staff providing testimony in support of Danskin cost recovery when the Company did not?

A. Danskin's plant cost recovery represents a large portion of increased revenue requirement requested in this case. Staff believes it is important to address the issue and provide the Commission with the Staff position.

Q. Has the Commission Staff audited the construction costs for the Danskin plant?

A. Yes. The total plant cost including the substation, step-up equipment, and structures and improvements is $52,484,209 as of year-end 2003.

Q. Do you believe all of the costs incurred for construction of the Danskin plant are reasonable and should be allowed in rate base?

A. Yes, I do. The plant's capital costs were projected to be $46 million upon completion in 2001. With an additional 20% for contingencies, Idaho Power's "Commitment Estimate" for the capital cost portion of the plant was $55.2 million. The Staff-audited cost of $52.5 million is clearly below the Company's commitment estimate.

Q. The Danskin plant was nearly as costly to build as the Bennett Mountain plant is expected to be, yet the Bennett Mountain plant will have a capacity of 162 MW compared to Danskin's 90 MW. Why was Danskin so expensive compared to Bennett Mountain?

A. The commitment estimate for construction of the Bennett Mountain plant is $54 million, while the cost of Danskin was $52.5 million. Bennett Mountain's unit cost, therefore, is expected to be $336 per kW, while Danskin's was about $583 per kW – more than 1.7 times the cost of Bennett Mountain.

One reasonable measuring stick for Danskin's plant cost is generating plant cost estimates prepared by the Northwest Power and Conservation Council for use in its Fifth Power Plan. The estimates were prepared on April 5, 2002, therefore, they are likely very representative of costs at the time Danskin was built. Although the Fifth Power Plan has yet to be released, its power plant cost assumptions have not changed. The Council's capital cost estimate for gas-fired simple cycle plants ranges from $540 to $660 per kW, with $600 per kW being the base case estimate. Danskin's cost of $583 per kW is very close to the Council's base case estimate.

Bennett Mountain's expected cost of $336 per kW is very low compared to simple cycle plant costs of just two years ago. The demand for gas turbines surged in the 1998-2001 time frame, peaking in 2000. During this time period, turbine manufacturers could not keep pace with orders for new equipment and buyers bargained with each other for higher slots on manufacturer's waiting lists. Since that time, however, electric market prices have moderated and demand for new gas turbines has plummeted. At the time Idaho Power committed to Bennett Mountain, turbines could be obtained at a highly discounted price. That is the primary reason Bennett Mountain is so much cheaper than Danskin on a cost per kW basis.

Q. What has been the actual cost of energy from Danskin?

A. The Company's Application in the Danskin Case

(Case No. IPC-E-01-12) indicated that the preliminary estimate of the levelized cost per MWh would range from an upper level of $223 per MWh based on a capital cost for the plant of $55.2 million, 500 hours of annual generation, and levelized fuel costs of $5.05 per MMBtu over the 30-year life of the plant, to a lower range cost of $77 per MWh based on a plant cost of $46 million, 5140 hours of annual dispatch, and average fuel costs of $5.05 per MMBtu. The actual cost of the plant ended up being closer to the high estimate, but the actual hours of operation has been close to the low estimate. Gas prices have varied substantially throughout the past two years, and the estimated gas price may still be reasonable over the 30-year plant life. Consequently, Danskin's actual energy costs have so far been much closer to $223 per MWh than to $77 per MWh. Future changes in gas prices and operating hours will, of course, change the cost of energy from the plant.

Q. If the cost of energy from Danskin is so expensive, why did Idaho Power build the plant?

A. First, it is important to recognize that the Danskin plant is a peaking plant, not a base-load plant. As a peaking plant, it is intended to be operated for only brief periods during peak hours in the summer and winter. Peaking plants will always have high energy costs due to their limited operating hours.

Second, it is important to remember the circumstances at the time the decision was made to construct the Danskin plant. Idaho Power made its decision to pursue construction in early 2001, at the height of the electric market price run-up. Idaho Power's marketing and trading analysts were predicting that heavy load period market prices for the next few years would likely be in the range of $50 to $350 per MWh, and that hourly prices could exceed $1000 per MWh in the near term. A severe drought also persisted throughout the Northwest at that time, which was part of the reason for such high market prices. This combination of exceptionally low stream flows and extremely high market prices forced utilities to scramble for alternatives to meet load.

Beginning in mid-2000, Idaho Power found it necessary to go to the electric market and make large purchases at extremely high prices. Consequently, the Company began deferring massive power supply costs unlike any that had been made before. The upper graph of Exhibit No. 124 shows the Company's PCA deferrals between 1999 and 2003. In <u>single months</u> from late 2000 to mid 2001, total deferrals frequently exceeded $20 million and sometimes approached $50 million. In early 2001, no one knew how much longer extremely high market prices would persist.

We did know, however, that drought conditions could not end until at least the following winter.

In response to the dire circumstances, in January 2001, Idaho Power began identifying alternatives to market purchases. In addition to building a simple-cycle peaking plant, the Company planned buy-backs from irrigators, ASTARIS and Simplot. The Company also planned to lease mobile diesel generators and to purchase hedges to guard against price volatility. Later, on May 1, 2001, anticipating continued high prices and poor stream flows, the Commission issued Order No. 28722 in Case Nos. IPC-E-01-7 and IPC-E-01-11, directing Idaho Power to prepare and file a report which would identify and outline plans for meeting loads during the summer and winter of 2001.

The Danskin project, with its short construction lead time, was intended to be on-line in time to provide a resource that could mitigate exposure to extremely high near-term market prices.

Q. Did Idaho Power issue a request for proposals or solicit bids for the Danskin project?

A. No, Idaho Power did not issue a request for proposals, nor did it formally bid the equipment contract or the construction contract. While conceding in Case No. IPC-E-01-12 that an ideal way to determine the cost of available alternative resources would be to initiate a request for proposals, the Company contended that pursuing the RFP route would likely have delayed the resource acquisition until 2002, thereby exposing the Company to increased levels of market purchases through fall and into the winter season.

Before the extreme price run-up began, however, Idaho Power did issue a Request for Proposals as a result of its 2000 IRP. The Company received proposals for gas-fired combustion turbines and coal-fired generation. In addition, the Company evaluated self-build alternatives using gas-fired combustion turbines. The Garnet proposal was eventually selected, although the project was later abandoned. The proposals received during this process gave Idaho Power at least some indication of the costs of new gas-fired generation. However, because the RFP was seeking 250 MW of capacity during a limited number of days in only five months, I do not believe the bids provided a fair approximation of the cost that could be expected for a 90 MW simple cycle plant. Although the RFP was broad enough that smaller projects could be proposed, only a handful of proposals were received in response to the RFP, and of the proposals received, only two were for less than the requested amount of capacity and energy.

In the Company's 2000 IRP, a number of other technologies for generation were evaluated, including coal, combined cycle gas, wind and other renewables. The evaluations were non-site-specific, however, and most were not realistic alternatives to building a simple cycle plant due to the urgency with which new generation was needed.

Q. How did the Danskin plant compare to the other alternatives available to Idaho Power at the time?

A. Obviously, one of the alternatives to constructing Danskin would have been to continue to make energy purchases from the market. However, given the exceptionally high prices, poor stream flow conditions, and the extremely high PCA deferrals, it was believed that continued reliance on the market would only exacerbate the problem.

Another option was to initiate buybacks with some of its largest customer groups. Idaho Power agreed to purchase 50 MW from ASTARIS for a two-year period at a cost of $159 per MWh. Thirty megawatts were also purchased from Simplot at $75 per MWh in the first year, $90 per MWh in the second year and 85% of market price in the third year. An additional block of 8 MW was purchased from Simplot at two-thirds of market price. A buy-back program for large commercial and industrial customers was also initiated, but no customers participated.

A buy-back program for irrigators was also implemented. The Company purchased 262 MW of load reduction at a cost of $150 per MWh.

Two large QF contracts, one with Simplot and one with Amalgamated Sugar, were also re-negotiated during this time frame.

Finally, the Company leased mobile diesel generators. The generators were capable of providing 39 MW at an estimated cost of $124 per MWh. Exhibit No. 125 provides a summary of the short-term programs and contracts pursued during this time period in response to the price run-up.

Over the course of time during which they were in effect, most of the programs proved quite expensive. The ASTARIS buy-back cost a total of nearly $128 million. The irrigation buy-back cost $86 million. The mobile diesel generators, despite never being used to satisfy load, cost almost $5.5 million. The lower graph on Exhibit No. 124 shows PCA deferrals by month as a result of each of these three measures. Compared to the total cost of these alternatives, Danskin's $52.5 million capital cost doesn't seem so large. In analyzing the Danskin project, Idaho Power estimated the present value of the revenue requirement over the 30-year expected plant life to be approximately $180 million.

Q. Didn't Idaho Power receive an unsolicited competing proposal for the Danskin plant?

A. Yes. Power Development Associates, LLC of Boise submitted a proposal to Idaho Power to install two 45 MW simple cycle gas turbines near Mountain Home at a site different than the Danskin site. The proposed turbines, I believed, were more efficient in a simple cycle mode than the turbines Idaho Power planned to install, but were less efficient in a combined cycle mode. Idaho Power eventually rejected the proposal primarily because of uncertainty about whether the project could come on-line soon enough to meet the Company's immediate need to be relieved of purchasing from the market.

As it turned out, Power Development Associates, LLC was the predecessor to Mountain View Power, Inc., the successful bidder to construct the Bennett Mountain plant. The site of the Bennett Mountain plant is the same as the site proposed as an alternative to Danskin. Bennett Mountain's plant capacity and equipment package is different than what was proposed initially, however. If Power Development Associates proposal had been selected as an alternative to Danskin, the Bennett Mountain plant would not have recently been available as an option.

Q. Do you believe Idaho Power adequately considered other alternatives to construction of the Danskin plant?

A. Yes, I do, given the circumstances that existed at the time the decision to build Danskin was made.

Q. What has been the history of operation of the Danskin plant so far?

A. Since the plant went on-line at the end of September 2001, the plant has operated on average about 500 hours per year. The plant has been operated most in the summer months, although it has operated at least some in every month of the year. Exhibit No. 126 shows the generation of the plant by month since it went on-line in September 2001.

Q. Will construction of the Bennett Mountain plant make the Danskin plant no longer useful?

A. No, I don't believe so. Operation of the Danskin plant could change after Bennett Mountain becomes available, but I believe Danskin will continue to be used to meet peak loads primarily in the summer and winter. Bennett Mountain will be a more efficient plant than Danskin, thus it will have a lower dispatch cost. However, Bennett Mountain will not always be able to meet the Company's peak load requirements by itself, making Danskin necessary. In addition, I think there could be times when Danskin would be dispatched before Bennett Mountain because Danskin's two 45 MW turbines can be dispatched independently, whereas Bennett Mountain will have a single 162 MW unit. Small peak load needs might be more economically met using Danskin despite its higher dispatch cost.

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

A. Yes, it does.