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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM MAY 16, 2008 THROUGH MAY 15, 2009

CASE NO. IPC-E-08-07

IDAHO POWER COMPANY

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

A. I am employed by Idaho Power Company as the Manager of Revenue Requirement in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. In May of 1975, I received a Bachelor of Science Degree in Mathematics with honors from Boise State University. In 2003, I attended the Public Utility Executives Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I continued to be the Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment (PCA) which would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission (IPUC) in 1992 at which time the IPUC established the PCA as an annual adjustment to the Company's rates. I sponsored the Company's annual PCA adjustment in each of the years 1996 through 2004. I supervised the preparation of PCA testimony presented by Ms. Schwendiman in years 2005 through this year.

Q. Are you the same Gregory Said that presented power supply and PCA testimony in the Company's last general revenue requirement case, IPUC Case No. IPC-E-07-08 ("07-08 case")?

A. Yes. In my testimony in the 07-08 case, I discussed changes in loads and resources since the Company's last general revenue requirement case, IPC-E-05-28, and the impact of those changes on the Company's power supply expenses. In the 07-08 case I sponsored the exhibits that provided the basis for determining the Company's normalized net power supply expenses for ratemaking purposes. I also discussed how the new normalized power supply expenses will impact future PCA computations until the Company's next general revenue requirement case.

Q. Why are you providing testimony in addition to the testimony Ms. Schwendiman is presenting in this proceeding?

A. Ms. Schwendiman's testimony provides the PCA computations required to determine PCA rates for the June 1, 2008 through May 31, 2009 time period consistent with standard Commission-approved methodology. However, in this case, the Company is requesting a one-year deviation from standard Commission-approved methodology. My testimony describes the Company's request for the one-year deviation and the reasons that the Company is making the request for the one-year deviation. In addition to the standard PCA computations, I instructed Ms. Schwendiman to compute the PCA based upon this deviation in methodology. Ms. Schwendiman's testimony provides the PCA computations required to determine a PCA rate using both standard computations and the Company's proposed alternative.

Q. With the Commission's approval of the 2007 test year settlement stipulation in the 07-08 case, what is the normalized level of net power supply expenses currently reflected in the Company's base rates?

A. As per the settlement stipulation, a

normalized net power supply expense level of $41.0 million and a normalized PURPA project expense level of $93.1 million are currently reflected in the Company's base rates.

Q. How are deviations from normalized PURPA expenses and normalized net power supply expenses reflected in PCA computational methodology?

A. As actual PURPA and power supply expenses are incurred, 100 percent of the deviation in actual PURPA expenses from base levels and 90 percent of the deviation in net power supply expenses from the forecast level are recorded in the deferral account.

For purposes of the Company's April 2008 through March 2009 forecast of PCA expenses, PURPA expenses are assumed to be at the normalized level, $93.1 million, with no anticipated deviation. In the forecast, net power supply expenses are determined by the regression formula described in Ms. Schwendiman's testimony. The forecast component of the PCA rate reflects 100 percent, or zero change, in PURPA expenses from base and 90 percent of the $18.7 million change in forecast net power supply expenses below base net power supply expenses.

Q. Have all of the new PURPA wind projects that were included in the test year determination of power supply expenses in the 07-08 case come on-line as anticipated?

A. No. Apparently a number of wind projects initially signed contracts to be on-line by the end of 2007 in order to receive tax credit benefits that required an on-line date prior to December 31, 2007. Once the tax credit benefits were extended, the wind projects sought to have their contracts amended to allow for later on-line dates. As a result, 62 average megawatts of energy that the Company had envisioned receiving in 2008 from new PURPA projects, will not be available and the Company will be forced to replace this amount of energy with purchases from the market.

Q. How will these reduced PURPA purchases and increased market purchases be reflected in the PCA?

A. One hundred percent of the benefits of reduced PURPA purchases will flow through the PCA to the benefit of customers while only 90 percent of the increased market purchases will flow through the PCA to customers. The Company estimates that PURPA expenses will be decreased by nearly $30 million dollars and that replacement energy from the market will exceed $40 million. The Company will not be able to recover $1 million for every $10 million of additional purchased power expense.

Q. What does the Company propose as a solution to this problem?

A. The Company is requesting that for a one year period of time, all deviations in net power supply and

PURPA expenses from levels included in base rates be tracked at 100 percent for both forecast and true-up purposes.

Q. Is there precedent for such an interim approach to one PCA item?

A. Yes. In Order No. 30508 the Commission approved the settlement of rate case and PCA issues that included a one year interim resolution regarding the load growth adjustment rate (LGAR) contained in the PCA true-up. In the Stipulation, the parties expressed their desire to undertake further good faith discussions prior to next year's PCA filing to address shortcomings of the LGAR methodology. In Order No. 30508, the Commission expressed its support for the parties' pursuit of good faith discussions on this PCA issue. The Company believes that the PCA sharing percentage is another potential PCA issue that should be addressed in a workshop environment.

Q. Are there other reasons why Idaho Power believes a one year deviation from the standard 90%-10% sharing of PCA costs and benefits should be approved?

A. Yes. At the time of this annual filing of the PCA, the Company has already committed to a number of purchase and sales hedging transactions in accordance with its Commission-approved Risk Management Guidelines. Hedging activity is not reflected in base rates and as is the case with PURPA purchases, compliance with the risk management policy is not subject to discretionary action, but is rather prescriptive in nature. At this time, the Company has a net hedging purchase position of nearly $51 million. Only 90 percent of this known amount will naturally flow through the PCA true-up mechanism.

Q. Does the prescriptive nature of the Company's hedging procedures have any implication for the 90%-10% sharing provision in the PCA?

A. Yes. As a result of the settlement of Case No. IPC-E-01-16, the Company's hedging for both overall system risk (in dollars) and volumetric risk (in MWh's) has been executed under very specific, Commission-approved procedures. Prior to the implementation of these procedures, the Company had discretion regarding the timing of advance purchase or sale of energy. This discretion was the primary rationale for the 90%-10% sharing ratio as a means to provide the Company with an incentive to make wise decisions with regard to the purchase or sale of energy. With the onset of the prescriptive buying and selling methodology embodied in the Risk Management Policy, the concept of providing incentives to encourage wise decisions based upon the Company's market price view has been greatly diminished. It is the Company's belief that because of the prescriptive risk management policy 100% pass-through of PCA expenses to customers is appropriate.

Q. Does the accuracy of PCA expense forecasts since the initial PCA forecast in 2003 impact the Company recommendation for a one-year deviation?

A. Yes. True-up amounts for the first seven years (1994 through 2000) were never more than $15.5 million above or below the forecast. During the energy crisis years of 2000 and 2001, the subsequent year true-ups 2001 and 2002 were $185.6 million and $223.3 million respectively. In the years 2004 through 2007, the true-up has not been less than $35 million.

Q. Have the large true-ups in years 2001 through 2007 corresponded with near normal streamflow conditions?

A. No. Six of the eight years 2000 through 2007 were drought conditions with hydro generation in the lowest 20 percent of historical conditions. Only one year, 2006 was above the middle 20 percent of historical conditions and one other year, 2000, was near normal. Over the eight year period of time (2000 through 2007) tracking at 90 percent rather than 100 percent has cost the Company nearly $100 million in unrecovered power supply expenses. Prolonged drought conditions have not resulted in symmetrical deviations from normalized levels reflected in base rates.

Q. Please summarize the rationale for one year tracking of deviations in net power supply and PURPA expenses as proposed by the Company.

A. The Company believes that in light of persistent drought conditions, the lack of inclusion of prescriptive hedging activities in PCA forecast methodology, and the failure of a number of PURPA projects to come on-line as envisioned in the last approved test year, it would be appropriate for the Commission to allow 100 percent tracking of net power supply and PURPA expenses in the 2008/2009 PCA year.

Q. What is the impact of the Company recommendation to allow 100 percent tracking of net power supply and PURPA expenses for the 2008/2009 PCA year on the quantification of the PCA rate contained in Ms. Schwendiman's testimony.

A. The computation of the true-up and true-up of the true-up components of the PCA are unaffected this year. The computation of the forecast rate, based upon 100% deviation of forecast power supply expenses from levels included in base rates, is a negative 0.1314 cents per kilowatt-hour as compared to Ms. Schwendiman's computation of a negative 0.1183 cents per kilowatt-hour for the 90%-10% sharing method.

Using 100% tracking provides the Company's customers with an immediate benefit due to a forecasted Brownlee runoff that is greater than the historical average runoff underlying base rates. If the actual year power supply expenses fall below base rate levels, customers will see additional benefits in next year's true-up computations. However, if the continued impacts of drought, continued deferrals of PURPA generation and prescriptive hedging activity results in positive actual power supply expense levels, the Company will be protected against another year of asymmetric recovery of power supply expenses.

Q. Does the Company view this 100 percent tracking of deviations in net power supply and PURPA expenses for one year as a response to a one-time problem?

A. It should come as no surprise that because of increased volatility in power supply expenses the Company believes that the 90%-10% sharing of PCA costs and benefits is not working as well today as it did in 1992 when the PCA was first implemented. The Company has addressed the problems associated with the 90%-100% sharing in the testimony of Mr. Steve Keen in the last two general rate cases (IPC-E-05-28 and IPC-E-07-08). Idaho Power believes that its one-year recommendation should be approved and the previously ordered LGAR workshops be expanded to include discussions as to appropriate PCA sharing levels into the future, as well as other methodological changes to the PCA.

Q. Does this conclude your testimony?

A. Yes.