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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 JUNE 1, 2013, THORUGH MAY 31, 2014.	)	CASE NO. IPC-E-13-10

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

Q. Please state your name and business address.

A. My name is Timothy E. Tatum and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Manager of Cost of Service in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I have earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the Utility Executive Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 as a Customer Service Representative in the Company's Customer Service Center where I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the areas of billing and metering.

In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the demand-side management ("DSM") expenses were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's 2004 Integrated Resource Plan ("IRP").

In August of 2004, I accepted a position as a Regulatory Analyst in Regulatory Affairs. As a Regulatory Analyst, I provided support for the Company's various regulatory activities, including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

In August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service and in April of 2011 I was promoted to Senior Manager of Cost of Service. As Senior Manager of Cost of Service, I oversee the Company's cost-of-service activities such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

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

A. The purpose of my testimony in this proceeding is to provide the Commission with an understanding of the factors that have impacted this year's Power Cost Adjustment ("PCA") quantification (including revenue sharing) as determined and described by Mr. Scott Wright in his testimony. The increase in PCA recovery based upon Mr. Wright's computations would be $140.4 million. However, my testimony will present for the Commission's consideration, a one-time PCA mitigation measure intended to lessen the impact of this year's PCA on customers by deferring $52.5 million of the PCA recovery until the 2014-2015 PCA resulting in an adjusted increase of $87.9 million.

Q. Please provide an overview of the intent and design of the PCA mechanism.

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual net power supply expenses ("NPSE") and the normalized level of NPSE recovered in the Company's base rates ("Base Level NPSE") for recovery or credit through an annual rate change each June 1. The PCA mechanism utilizes a 12 month test period of April through March ("PCA Year") and is composed of a forecast component ("PCA Forecast") and a true-up component ("PCA True-up"). The PCA Forecast is based on the Company's March Operating Plan and represents the difference between the NPSE forecast from the March Operating Plan and the Base Level NPSE recovered in the Company's base rates. The PCA True-up includes a backward-looking tracking of differences between the prior year's PCA Forecast and actual NPSE incurred by the Company during the prior PCA year. The PCA True-up contains a second component that tracks the collection of the prior year's true-up amount, referred to as the "true-up of the true-up."

With the exception of Public Utility Regulatory Policies Act of 1978 ("PURPA") expenses and demand response incentive costs, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared to the Base Level NPSE, whether positive or negative. The PCA is also the rate mechanism used by the Company to provide any revenue sharing benefits resulting from the revenue sharing mechanism approved by Order No. 32424, which is described in detail by Ms. Kelley Noe in her testimony in this proceeding.

Q. Please provide a summary of the sections presented in your testimony.

A. My testimony contains five sections. The first section provides an overview of the 2013-2014 PCA amount and the year-over-year differences that contribute to this year's PCA rate change. The second section provides a review of the factors that contributed to this year's true-up amount and presents this year's revenue sharing amount. The third section describes the PCA Forecast amount and the main drivers of that amount. The fourth section provides a regulatory history related to PCA impact mitigation. In the final section of my testimony, I present a one-time PCA rate impact mitigation alternative for the Commission's consideration.

I. <u>2013-2014 PCA OVERVIEW</u>

Q. What is the total PCA amount as measured from Base Level NPSE for the 2013-2014 PCA Year?

A. As quantified by Mr. Wright and presented in his testimony, the 2013-2014 total PCA amount as measured from Base Level NPSE is $158.5 million. This represents a year-over-year change of $140.4 million when measured from the 2012-2013 PCA amount of $18.1 million. The following Table 1 presents the differences that exist between this year's PCA and last year's PCA segmented into the three main components of the PCA: 1) the PCA Forecast, 2) the PCA True-up, and 3) Revenue Sharing.

Table 1: PCA Revenue Comparison (Idaho Jurisdiction Amounts*)

	2013-2014 PCA	2012-2013 PCA	Difference
PCA Forecast	$111,145,245	$68,627,949	$42,517,296
PCA True-Up	$54,482,435	$(23,311,161)	$77,793,596
Revenue Sharing	$(7,151,221)	$(27,211,527)	$20,060,306
Total PCA Increase	$158,476,459	$18,105,261	$140,371,198

(*) Idaho jurisdictional PCA component amounts for the 2013-2014 PCA and the 2012-2013 PCA represent the respective PCA rate components applied to the June 2013 through May 2014 sales forecast.

Q. Please describe the information contained in Table 1.

A. Table 1 demonstrates the extent to which each PCA component contributes to the year-over-year change in required PCA revenue. As can be seen on Table 1, this year's PCA Forecast component is $111,145,245, which is $42,517,296 higher than last's year's PCA Forecast of $68,627,949. This year's PCA True-Up component is $54,482,435. Last year's PCA True-Up component was negative $23,311,161, representing a credit to customers for over collection of the prior year's actual NPSE. The difference between this year's PCA True-Up component and last year's PCA True-Up component is a year-over-year change of $77,793,596. This year's revenue sharing component is a credit of $7,151,221, which is $20,060,306 less than last year's revenue sharing amount of $27,211,527.

Q. Is there any information contained in Table 1 that is particularly noteworthy?

A. Yes. It is particularly noteworthy that two of the three PCA components in last year's PCA (the PCA True-up and Revenue Sharing) when combined, represented nearly $50 million in credits that expire with the implementation of this year's PCA. In other words, of the $140,371,198 increase in required PCA revenue this year, nearly $50 million is related to the expiration of rate credits. This is an important factor to consider when assessing the overall magnitude of the year-over-year change in the PCA this year.

II. **<u>PCA TRUE-UP AND REVENUE SHARING</u>**

Q. What are the most significant factors that contributed to this year's PCA True-up amount of approximately $54.5 million?

A. The two most significant factors that contributed to this year's True-up amount were 1) lower actual hydro generation as compared to the 2012-2013 forecasted amount and 2) lower actual market energy prices as compared to the 2012-2013 forecasted prices. Both of these factors contributed to lower surplus energy sales revenue ("surplus sales"), which serves to offset power supply expenses recovered from customers.

In the 2012-2013 PCA Year, surplus sales were forecasted to be $110,167,401. Actual surplus sales in the 2012-2013 PCA Year were $48,751,418, or approximately 44 percent of the forecasted amount. Attached as Exhibit No. 5 to my testimony is an analysis prepared at my direction that provides additional detail regarding the factors contributing to reduced surplus sales during the 2012-2013 PCA Year.

Q. How did actual hydro generation compare to the forecasted amount of hydro generation in the 2012-2013 PCA Year?

A. As can be seen on page 1 of Exhibit No. 5, hydro generation for the 2012-2013 PCA Year was forecast to be 8.7 million megawatt-hours ("MWh"). Actual hydro generation for the 2012-2013 PCA Year was 6.9 million MWhs, 1.8 million MWhs less than had been forecasted.

Q. In recent years, Idaho Power has been able to forecast its hydro generation for PCA purposes with reasonable accuracy. Why was there such a dramatic difference between the forecast and actual hydro generation in the 2012-2013 PCA Year?

A. The forecast of April through July Brownlee Reservoir inflows in last year's March Operating Plan was

5.69 million acre feet ("MAF"). Actual April through July Brownlee Reservoir inflows were 5.52 MAF, only slightly lower than the forecasted amount. However, there were three factors that could not have been known at the time of the forecast that contributed to lower than forecasted levels of hydro generation in the 2012-2013 PCA Year. First, following the completion of the March 2012 Operating Plan forecast, the U.S. Bureau of Reclamation decreased stream flows at Milner Dam because of above normal irrigation demand and efforts to refill Palisades Reservoir. Because Milner Dam is located at the upper end of Idaho Power's hydro system, any reduction of stream flows at Milner Dam results in reduced hydro generation at almost all of Idaho Power's hydroelectric projects. It is estimated that the reduced stream flows at Milner resulted in a cumulative loss of over one million acre feet of flow past Milner in 2012.

The second factor contributing to lower than forecasted hydro generation was a shortened run-off season caused by warmer than average temperatures in the spring of 2012. These warmer temperatures shifted Brownlee Reservoir inflows expected for May and June into the month of April. This occurred during a period when Idaho Power was subject to the U.S. Army Corps of Engineers' flood control requirements. Instead of capturing the additional April inflows in the reservoir for future generation, the flood control requirements dictated that Idaho Power "spill" much of the additional inflow through the dam, thereby losing future generation potential. This loss of potential hydro generation in April was exacerbated by a third factor - an unplanned forced shutdown of Unit 5 at the Brownlee power plant from April 1 through April 26. Unit 5 at the Brownlee power plant is Idaho Power's largest single generating unit, with a nameplate capacity of 225 megawatts.

In addition to the three factors mentioned above, a drier than normal 2012/2013 winter reduced expected stream flows to below the expected case in the latter half of the PCA Year. Detail regarding these events and their impact on the Company's hydro generation is presented on pages 1-3 of Exhibit No. 5.

Q. Did the Company take any action to reduce the impact that the flood control requirements had on its ability to generate power from its Hells Canyon Complex?

A. Yes. Idaho Power's hydrology team was in frequent contact with representatives from the U.S. Army Corps of Engineers to ensure that the Company was able to maximize the generation potential of the stream flows in the hydro system. These discussions ultimately resulted in the U.S. Army Corps of Engineers allowing the Company to begin refilling the Brownlee Reservoir on April 26, 2012, five days earlier than the planned date of May 1, 2012.

Q. How did actual market prices differ from forecasted market prices in the 2012-2013 PCA Year?

A. Market prices were lower than forecasted in the 2012-2013 PCA Year, reducing the overall value of surplus sales.

Q. How did the lower market prices impact the level of surplus sales in the 2012-2013 PCA Year?

A. Lower market prices impacted Idaho Power's ability to economically dispatch its thermal units for surplus sales. That is, when market energy prices are near or below the dispatch price of the Company's thermal generators, it becomes uneconomical to operate the plants for surplus sales.

Q. What impact does revenue sharing have on this year's PCA?

A. As described by Ms. Noe in her testimony, the Company's 2012 Idaho jurisdictional earnings were at a level that provides for approximately $7.2 million in direct benefits to customers as part of this year's PCA. While this year's revenue sharing amount is a benefit to customers, it is approximately $20.1 million less than last year's shared benefit. The effect of the reduction in annual rate benefit is an increase in required PCA-related revenue of $20.1 million.

III. PCA FORECAST

Q. What are the main factors contributing to the increase in the PCA Forecast this year?

A. As stated earlier in my testimony, the PCA Forecast for the 2013-2014 PCA Year is $111,145,245, which is $42,517,296 higher than last year's PCA Forecast of $68,627,949. The most significant factor contributing to the approximately $42.5 million year-over-year difference is lower than expected hydro generation. The Company is forecasting 6.8 million MWhs of hydro generation for the 2013-2014 PCA Year, approximately 22 percent below last year's forecast. As a result of the lower hydro generation, this year's forecast anticipates increased coal and gas production and lower surplus sales revenue when compared to the prior year's forecast. Table 2 presents a comparison of this year's PCA Forecast to last year's PCA Forecast by PCA component on a total system basis.

Table 2: PCA Forecast Comparison (Total System-Level)

	2012-2013 Forecast	2013-2014 Forecast	Difference
Coal	$147,503,921	$165,951,392	$18,447,471
Water for Power	$2,521,000	$2,354,374	$(166,626)
Gas	$52,250,517	$66,536,064	$14,285,547
Non-PURPA	$41,169,588	$40,080,534	$(1,089,054)
3rd Party Transmission	$7,554,520	$6,692,385	$(862,135)
Hoku First Block	$(6,765,150)	-	$6,765,150
Surplus Sales	$(110,167,401)	$(98,510,169)	$11,657,232

Net 95% accounts	$134,066,995	$183,104,580	$49,037,585
PURPA	$129,590,113	$131,731,526	$2,141,413
Demand Response Incentive	$14,723,210	$4,668,960	$(10,054,250)
Net 100% accounts	$144,313,323	$136,400,486	$(7,912,837)

Q. Please describe the information included in Table 2.

A. As can be seen in Table 2, coal and gas production costs are expected to increase from last year's forecast by a combined $32.7 million. Water for Power, non-PURPA market purchases and 3rd Party Transmission expenses combined represent an approximate $2.1 million reduction as compared to last year's PCA Forecast. The loss of expected revenue from Hoku Materials Inc. ("Hoku") represents a year-over-year difference of $6.8 million. Finally, surplus sales revenue is forecast to decline year-over-year by approximately $11.7 million. The combined impact of these differences represents approximately $49.0 million on a system-basis.

Q. How have the costs associated with PURPA projects changed since last year's PCA Forecast?

A. The year-over-year change in PURPA costs is a relatively small increase of approximately $2.1 million on a system-basis.

Q. In Order No. 32776, the Commission recently approved a Settlement Stipulation under which the Company will suspend the operation of two of its three demand response programs in 2013. What impact does the suspension of the demand response programs have on this year's PCA Forecast?

A. As compared to last year's PCA Forecast, reduced demand response incentive costs are forecast to benefit Idaho customers by approximately $10.1 million on an Idaho jurisdictional basis.

Q. Are there any other factors contributing to the year-over-year difference in required PCA Forecast revenue?

A. Yes. On June 29, 2012, the Langley Gulch combined cycle power plant became operational. On July 1, 2012, the Company was authorized to change its base rates to reflect the incremental revenue requirement associated with the Langley Gulch plant. At the same time, the Company reduced the Base Level NPSE included in base rates by approximately $7.7 million to reflect the economic benefits of this new plant. Because the PCA Forecast represents the difference between the NPSE forecast from the March Operating Plan and the Base Level NPSE recovered in the Company's base rates, this change in Base Level NPSE related to Langley Gulch serves to increase the deviation measured by the PCA Forecast. In other words, when comparing the year-over-year change in the PCA Forecast, one must also consider that the Base Level NPSE was reduced by approximately $7.7 million, resulting in a direct increase to the measured deviation.

IV. **HISTORY OF PCA MITIGATION**

Q. How does this year's PCA compare to historical PCA rate adjustments?

A. To provide a meaningful comparison of PCA rate adjustments over time, PCA amounts should be compared without the revenue sharing component. While revenue sharing is currently a component of the PCA, it was not a component prior to the 2012-2013 PCA Year; therefore, the inclusion of revenue sharing would not allow for an equivalent comparison across all years.

This year's total PCA amount as measured from Base Level NPSE, excluding revenue sharing, is $165.6 million and represents a year-over-year change of $120.3 million or approximately a 13.1 percent increase over current billed revenue of $915.2 million. Since the inception of the PCA in 1993, the single largest PCA increase was $244.4 million in 2002 associated with the 2002-2003 PCA Year. The second largest year-over-year change in PCA revenue was associated with the PCA approved in 2001, which allowed recovery of an incremental $217.2 million in PCA revenue phased in over two rate adjustments. The first PCA rate adjustment occurred on May 1, 2001, and allowed collection of $168.3

million over a one-year period. The second PCA rate adjustment occurred on October 1, 2001, and allowed collection of the remaining $48.9 million over a one-year period.

Q. Did the Commission approve any mitigation of the rate impact related to the 2002 PCA?

A. Yes, however, only minimally. In Order No. 29026, the Commission denied the Company's proposal to "securitize" a large portion of the 2002 PCA amount through the issuance of up to $172 million in bonds, which would have significantly lessened the single-year rate impact. Under the proposal, the Company would have recovered up to $172 million with carrying charges from customers over a three-year period. Instead of accepting the Company's mitigation proposal, the Commission chose to adjust rates to recover $244.4 million over a single year and deferred the recovery of $11.5 million to be collected from Irrigation and Small General Service customers in the following year, citing special circumstances that existed related to those two classes of customers.

On page 16 of Order No. 29026, the Commission made the following statement with regard to its view on PCA rate mitigation:

> While the Commission understands the reasons why cost recovery or some portion thereof might be amortized over

> time, the Commission largely declines to adopt this recommendation. As with any requested rate increase, the Commission must balance the needs of the Company to maintain its financial viability and recover its reasonable expenses with customer concerns of fair rates and rate stability. During the last two years extraordinary conditions have resulted in large purchase power costs and a low water forecast. Given the amount of purchases the Company has already made, it is reasonable and appropriate for the Company to recover the majority of the $255.9 million approved for recovery within the normal one-year timeframe.

On pages 16 and 17 of that same Order, the Commission went on to state the following:

> We are also reluctant to create a situation where customers are required to continue paying costs from this year on top of whatever increases may be required in future years.

Q. Has it been a common practice of this Commission to spread the recovery of a single-year's PCA amount over multiple years?

A. No, not with regard to Idaho Power's PCA. However, in Order No. 24806 (at page 14) issued March 29, 1993, approving the implementation of the PCA, the Commission stated its desire to preserve its ability to "ameliorate the 'rate shock' that could result during periods of low water." Consequently, the Commission reserved the ability to investigate deferral of a percentage of PCA-related NPSE recovery if forecasted increases above the normalized NPSE are expected to exceed 7 percent of normalized base revenues. The Commission made the following statement with regard to the 7 percent notification limit:

> We have chosen this 7% notification limit based upon historic variations in power supply costs. This limit will allow the PCA to operate uninterrupted in most years but will guard against extreme rate shock in very poor water years. This method will also allow the Commission to take into account the accumulative effects, in any, of true-up recovery for prior year adjustments.

Order No. 24806 at 14.

Q. Has the Commission ever utilized the 7 percent notification limit to mitigate the PCA's impact on customers?

A. No. In fact, the Commission has on a number of occasions expressed its opposition to spreading the collection of PCA amounts over multiple years. As part of its order regarding the 2001 PCA, the Commission made the following statement:

> While the Commission is sympathetic to the request that the authorized rate increase or some portion thereof be amortized over time, the Commission declines to adopt this recommendation.

Order No. 28722 at 26.

As part of its order regarding the 2002 PCA, the Commission made the following statement:

> The Commission is also concerned that the longer the power supply cost recovery is delayed, the greater the risk that the customers taking service when deferred costs were incurred will not be the same customers that will later pay for them.

Order No. 29026 at 15.

As part of its order regarding the 2008 PCA, the Commission made the following statement:

> It is simply too risky, and potentially compounds the problem, to seek recovery from ratepayers across three future years.

Order No. 30563 at 7.

As part of its order regarding the 2009 PCA, the Commission made the following statement:

> Despite the significant amount included for recovery in the PCA this year, the Commission declines to spread recovery of the amount into a subsequent year.

Order No. 30828 at 10.

Q. Do you believe that the 7 percent notification limit related to PCA increases over normalized base revenues is an appropriate percentage for mitigation of PCA increases at this time?

A. No. While I would agree that the 7 percent notification limit related to PCA increases over normalized base revenues may provide a reasonable threshold to alert the Commission to evaluate potential deferral of a portion of PCA increases, it is not an appropriate mitigation percentage for a number of reasons. First, the Company's normalized base revenues do not reflect the current normalized Base Level NPSE, but rather a much lower Base Level NPSE, which reflects 2010 load and cost inputs. Second, the PCA includes components that did not exist at the time the 7 percent notification limit was contemplated such as demand response program incentive cost recovery and revenue sharing.

Q. How do the normalized Base Level NPSE included in current base rates compare to the normalized Base Level NPSE that would exist if updated to a 2013 calendar year?

A. The Company believes that the Idaho jurisdictional normalized Base Level NPSE included in current base rates is nearly $100 million below the normalized Base Level NPSE that would exist if updated to a 2013 calendar year. The following table presents normalized Base Level NPSE based on 2013 loads and cost inputs that would result from applying the Commission-approved method of deriving normalized NPSE as compared to the current Base Level NPSE:

Table 3: System-Level NPSE

	Langley NPSE (current base)	2013 NPSE 2012 PURPA	Difference
Account 501, Coal	$167,192,744	$107,170,238	($60,022,506)
Account 536, Water for Power	$1,828,640	$1,828,640	$0
Account 547, Other Fuel	$51,934,201	$31,259,782	$(20,674,419)
Account 555, Purchased Power Non-PURPA	$45,510,093	$61,400,706	$15,890,613
Account 555, PURPA	$62,851,454	$135,811,845	$72,960,391
Account 555, Demand Response Incentives	$11,252,265	$11,252,265	$0
Account 565, 3rd Party Transmission	$8,262,000	$8,262,000	$0
Account 447, Surplus Sales	$(124,916,153)	$(55,833,279)	$69,082,874
Account 442, Hoku 1st Block	$(23,921,467)	$0	$23,921,467
Total Net Power Supply Expenses	$199,993,776	$301,152,198	$101,158,421

As can be seen in Table 3, each major NPSE cost and revenue component would change significantly if updated to reflect 2013 input values. On a total system basis, these NPSE categories would change by approximately $101 million.

Q. How is the difference that exists between normalized Base Level NPSE included in current base rates and the normalized Base Level NPSE that would exist if updated to a 2013 calendar year relevant when discussing the Commission's 7 percent notification provision?

A. The Commission's 7 percent notification provision was envisioned to be measured from current normalized base revenues. Under this approach, simply updating the Company's normalized Base Level NPSE included in base rates with current 2013 normalized Base Level NPSE would result in an increase greater than 10 percent. This is prior to including the impacts of this year's below normal stream flow conditions. Therefore, because the PCA is collecting a large portion of the increase in normalized NPSE that has occurred over the last few years, the 7 percent notification provision is not an appropriate rate impact mitigation percentage to apply at this time.

V. IDAHO POWER'S PCA MITIGATION ALTERNATIVE

Q. Did the Company evaluate potential options to mitigate the impact of this year's PCA on customer rates?

A. Yes. Even though the Company continues to believe that the normal operation of the PCA mechanism is appropriate, Idaho Power also understands the burden that rate increases can place on its customers. While the Company does not believe the 7 percent notification provision is an appropriate mitigation percentage, Idaho Power has nonetheless developed for the Commission's consideration an alternative method of mitigating the impact of this year's PCA on customer rates.

Q. What is the Company's alternative method of mitigating this year's PCA rate impact on customers?

A. Idaho Power favors matching cost recovery as close as possible with the period in which power supply costs are incurred. This matching minimizes compounding or "pancaking" of rates that could harm customers more in the future than a deferral would help those same customers today. Notwithstanding this view, if the Commission wishes to lessen the rate impact on customers in this year's PCA, the Company recommends that the Commission consider deferring recovery of 100 percent of the year-over-year increase in the PCA Forecast of $42.5 million to the 2014-2015 PCA Year. To further mitigate this year's PCA impact, the Commission may also consider deferring $10.0 million associated with this year's PCA True-up balance for recovery in the 2014-2015 PCA Year. The combination of these two adjustments would defer approximately $52.5 million to be recovered from customers in the 2014-2015 PCA Year.

Q. How did the Company arrive at its PCA mitigation alternative?

A. When the Company's Senior Executive Officers ("Officers") became aware that this year's PCA may result in an average increase for Idaho customers of greater than 10 percent, the Officers directed me to look for ways to reduce this year's PCA rate impact that could ultimately be presented to the Commission for its consideration. As part of this directive, the Officers asked me to first evaluate mitigation adjustments to only the forecast component of the PCA. This instruction was premised on the Company's belief that the change in PCA revenue related to past events such as the expiration of rate credits from revenue sharing or last year's negative PCA True-up starting balance should be passed on to customers through a single rate adjustment and not deferred to a subsequent period. The Company believes that any PCA mitigation should exclude the revenue sharing component in its entirety.

As mentioned earlier in my testimony, this year's revenue sharing amount is a benefit to customers; however, it is approximately $20.1 million less than last year's sharing amount. The effect of the difference in annual rate credits is an increase in PCA-related revenue of $20.1 million. Consistent with the treatment of revenue sharing credits, the Company believes that the expiration of rate credits related to last year's PCA True-up balance should not be included in any mitigation decisions.

The final aspect of the Officer's directive was that I develop a PCA mitigation alternative that would reduce the overall PCA rate impact for this year below an average increase of 10 percent.

Q. Based on the Officer's directive, what steps did you take to develop your mitigation recommendation?

A. As directed, I first looked at the impact of deferring recovery of 100 percent of the year-over-year increase in the PCA Forecast of $42.5 million to the 2014-2015 PCA Year. Unfortunately, the deferral of only the $42.5 million to the 2014-2015 PCA Year would have only reduced the average PCA increase to approximately 10.7 percent overall. Because the Company's goal was a mitigation result of below a 10 percent increase, I further analyzed the impact of deferring an additional $10.0 million related to this year's PCA True-up to the 2014-2015 PCA Year. The combined impact of both adjustments would result in a PCA increase of just below 10 percent overall, and as a result, was ultimately accepted by the Officers as the Company preferred mitigation option for this year's PCA.

Q. What is the adjusted PCA rate impact that would result from applying the Company's PCA mitigation alternative?

A. Should the Commission wish to apply the mitigation adjustments presented by the Company, this year's PCA increase would be reduced from $140.4 million to $87.9 million. This represents an overall increase of approximately 9.6 percent over current billed revenue.

Q. The Commission has in the past been reluctant to defer PCA collection to subsequent years. Why might the Commission consider approving the Company's mitigation alternative in this case?

A. It is my belief that when the Commission has considered PCA mitigation in the past it has tried to balance the impact that any mitigation may have on the financial health of Idaho Power with a desire to maintain fair rates and rate stability. As cited in my testimony, the Commission has also been careful to avoid a situation where deferred cost recovery is compounded with a subsequent year's PCA increase, often referred to as "pancaking."

First and foremost, the Company believes that its mitigation proposal would satisfy the Commission's desire to maintain fair rates and rate stability. With regard to the Commission's consideration regarding the financial impact of PCA mitigation on the utility, the Company's Officers share the Commission's concerns and feel that the PCA has been an important aspect of establishing the ongoing credit worthiness of Idaho Power. At this time, the Company's liquidity position is good, partly aided by federal tax policy and bonus depreciation, which have offered favorable cash recovery of investments. The Company's Officers believe that Idaho Power will be able to withstand the one-time cash flow impact of the PCA mitigation alternative without suffering material financial harm, while tempering the impacts to its customers over a multi-year period.

With regard to the Commission's view of potential "pancaking," it is important to consider the hydrologic forecast for the 2013-2014 PCA Year. The hydrologic forecast for the 2013-2014 PCA year has an expected case water condition that is relatively close to the low case water condition, which suggests that the risk of the Company experiencing lower than forecast hydro generation is relatively low, particularly for the remainder of the 2013 water year, which extends through the coming September.

For the 2014 water year, a repeat of below normal precipitation during the 2013-2014 winter would result in lower than forecast flood control releases from federally-managed reservoirs above Brownlee Reservoir, leading to lower than forecast hydro generation. This would negatively impact hydro generation expectations for the first part of 2014, including notably the last three months of the 2013-2014 PCA year. Nevertheless, the forecast hydro generation for the entire 2013-2014 PCA Year is markedly lower than the forecast for the 2012-2013 PCA Year. This suggests there is simply less downside risk associated with the 2013-14 PCA year forecast as compared to the 2012-2013 PCA Year.

Finally, because this year's hydrologic conditions are forecast to be poor compared to historical records, it is unlikely that next year's conditions will materially worsen. While the Company recognizes that it does not have perfect foresight into future hydrologic conditions, the existing probabilities suggest that compounding or "pancaking" of rate impacts resulting from worsening hydrologic conditions is less likely this year than in years with better hydrologic conditions.

Q. Does the Company believe that its PCA mitigation alternative should establish precedent for future rate impact mitigation?

A. Absolutely not. The Company's PCA mitigation alternative in this case is intended to address the unique set of circumstances that exist with the 2013-2014 PCA.

Q. Has the Company prepared a revised Schedule 55 that presents the PCA rates that would result from applying the Company's mitigation alternative?

A. Yes. Attachment No. 2 to the Application is a revised Schedule 55, in both clean and legislative formats, specifying the proposed PCA rates and changes for providing electric service to customers in the state of Idaho with $87.9 million to be collected during the 2013-2014 PCA year and $52.5 million of the PCA recovery deferred until the 2014-2015 PCA year.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada   )

I, Timothy E Tatum, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as a Senior Manager in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 15th day of April, 2013.

Timothy E Tatum

Timothy E. Tatum

SUBSCRIBED AND SWORN to before me this 15th day of April, 2013.

Kimberly K. Towell

Notary Public for Idaho
Residing at: Star, ID
My commission expires: 12-20-2014

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-10

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 5

Date: April 9, 2013

To: Tim Tatum, Cost of Service Manager

From: Philip DeVol, Resource Planning Leader

Subject: 2012-2013 Surplus Sales Forecast Compared to Actual

This memo is intended to address the variances between the 2012-2013 PCA forecast and the actual amounts for both the hydro generation and surplus sales components of the PCA. The differences between forecasted and actual amounts are shown below.

	Forecast	Actual	Variance
Hydro Generation (000s MWh)	8,674	6,898	1,776
Surplus Sales (000s MWh)	4,056	1,711	2,346
Surplus Sales (000s of dollars)	110,167	48,751	61,416

Hydro Generation

Actual hydro generation was lower than anticipated in almost every month of the PCA period as shown in the table below.

Hydroelectric Generation (000's MWh)

	2012 Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2013 Jan	Feb	Mar	Total
Forecast	1,113	1,084	928	733	535	492	422	401	617	719	793	838	8,674
Actual	889	795	729	651	485	513	432	359	535	504	512	494	6,898
Variance	(224)	(288)	(199)	(82)	(50)	21	11	(42)	(82)	(215)	(281)	(344)	(1,776)

Since the water year runs from October 1 through September 30, the PCA year crosses two water years. The first four months of the PCA year (April through July) are the critical runoff months for the water year. Halfway through the PCA year (October) is the beginning of the new water year and the last four months of the PCA year (December through March) is when the snowpack is accumulating and a better understanding of the new water year is known. For these reasons, the discussion here is separated into the April-July run-off period and the December-March snow accumulation period.

April - July

The variances for April, May, June, and July were caused by three major factors. First, immediately following the March Operations Plan, the U.S. Bureau of Reclamation (USBR) dramatically decreased streamflows at Milner. The USBR was reacting to high irrigation demand brought on by high temperatures the first week of April. For example, the projected streamflow past Milner for April was 7,220 cfs, but actual streamflow was 4,173 average cfs. Since Milner is at the beginning of our system, this loss of inflow reduced generation throughout our Snake River hydro system. This loss of inflow continued through the PCA year accumulating to a total reduction in flow past Milner of over one million AF. A monthly summary is shown below.

	Flows Past Milner (million acre-feet)												
	2012									2013			
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Forecast	0.43	0.25	0.24	0.16	0.05	-	0.02	0.02	0.16	0.23	0.22	0.13	1.92
Actual	0.25	0.02	0.17	0.07	0.04	0.00	0.00	0.02	0.03	0.03	0.03	0.02	0.69
Variance	(0.18)	(0.22)	(0.07)	(0.09)	(0.00)	0.00	(0.02)	(0.01)	(0.13)	(0.20)	(0.19)	(0.11)	(1.23)

The second major factor, also caused by the warm temperatures, was a short runoff season. Snowpack typically melts in a fairly even pattern across April, May, and June; however, in the 2012 runoff season, nearly 40 percent of the total spring inflow to Brownlee occurred in April. The following table shows the forecasted and actual inflow for the spring months.

	Brownlee Inflow (MAF)				
	Apr	May	Jun	Jul	Total
Forecast	1.69	1.90	1.30	0.80	5.69
Percent of APR-JUL Inflow	30%	33%	23%	14%	
Actual	2.06	1.71	1.03	0.71	5.52
Percent of APR-JUL Inflow	37%	31%	19%	13%	

While the forecasted total inflow from April – July was fairly accurate, this shift of run-off to April from June had a significant impact on Idaho Power's annual generation. Idaho Power is required by the Corp of Engineers to meet flood control requirements, measured by the Brownlee headwater level, on March 31, April 15, and April 30. When there is additional runoff during the flood control season, Idaho Power cannot capture that inflow in the reservoir for use at a later time. Instead, the company must pass the inflow through the canyon and reduce the reservoir to the required levels. The table below summarizes the headwater levels required by the Corps of Engineers for the 2012 flood control season.

2012 Flood Control Requirements	
Date	Brownlee Headwater (in feet)
3/31	2,042.9
4/15	2,034.4
4/30	2,014.3

During the months of March and April, Idaho Power's Operations Hydrology team was in frequent contact with the Corps and received permission to begin refilling the reservoir on April 26 rather than May 1. Beginning Brownlee headwater on March 1 was 2054.34' and reached a low of 2021.77' before Idaho Power was allowed to begin refilling the reservoir.

Finally, the generation capacity in the canyon is limited. Regardless of the level of water flowing, the turbines have limited hydraulic capacity. And, due to an unplanned maintenance outage from April 1 through April 26, Brownlee was limited to 22,700 cfs, down from its normal capacity of 35,000 cfs. The outage was at Unit 5, Idaho Power's largest hydro generation unit, with a nameplate capacity of 225 MW.

When Idaho Power is in the position of meeting required flood control levels and inflows are in excess of the capacity of the units, spill occurs. That is, water is passed through project spillgates, and no generation is gained from that water. The table below shows the generation capacity of the dams and the average inflow for the month of April. Maximum inflows for March, April, and May were 36,306, 43,111, and 27,745, respectively. This table does not include additional flows due to changes in reservoir levels.

Brownlee Inflows Compared to Plant Capacity

	Mar	Apr	May
Maximum actual inflows	36,306	43,111	36,669
Average actual inflows	23,796	34,677	27,745
Hells Canyon capacity	30,500	30,500	30,500
Oxbow capacity	28,000	28,000	28,000
Brownlee capacity	35,000	22,700	35,000

December – March

A water year calendar begins on October 1 and runs through September 30. While the 2012 March Op Plan included a forecast for the 2013 water year, information with such a long lead time is limited and Idaho Power relies on a median or normal water year forecast. Idaho Power also forecasts for a low and high water condition, but uses the expected forecast for the PCA forecast.

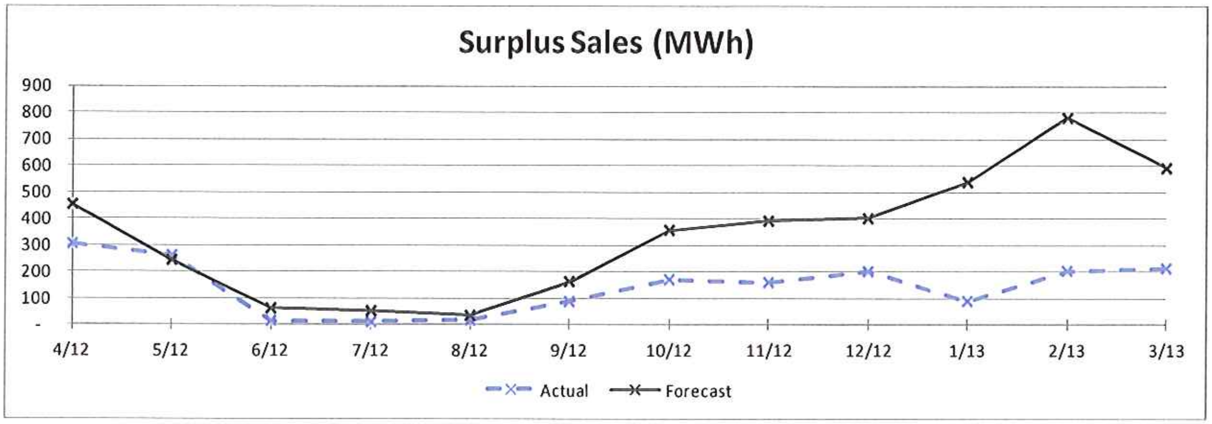
As we progress through the water year, we have experienced a drier than normal winter that has been closer to our low water case than our expected water case. In December, inflows were low due to warmer than normal temperatures. Precipitation came in the form of rain rather than snow, and, after a hot, dry summer, the soil absorbed the rainfall. Conversely, in January, we experienced very cold temperatures that caused rivers to turn to ice and reduced normal inflows.

Surplus Sales

Surplus sales were impacted by both lower hydroelectric generation due to lower than anticipated snowpack and lower thermal generation due to lower than projected market prices. The dollar variance (in millions of dollars) is shown by month in the table below with the largest variances in surplus sales occurring between October 2012 and March 2013. The graph below the table further demonstrates the variance of forecasted MWh sales volume as compared to actual MWh sales volume by month.

Surplus Sales (in millions of dollars)

	2012 Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2013 Jan	Feb	Mar	Total
Actual	5.1	4.5	1.5	0.2	0.7	3.6	5.2	4.5	7.7	3.4	6.3	6.0	48.7
Forecast	7.5	3.3	1.8	1.3	1.0	5.8	10.3	11.0	13.4	16.4	22.5	15.8	110.1
Variance	(2.4)	1.2	(0.3)	(1.1)	(0.3)	(2.2)	(5.1)	(6.5)	(5.7)	(13.0)	(16.2)	(9.8)	(61.4)



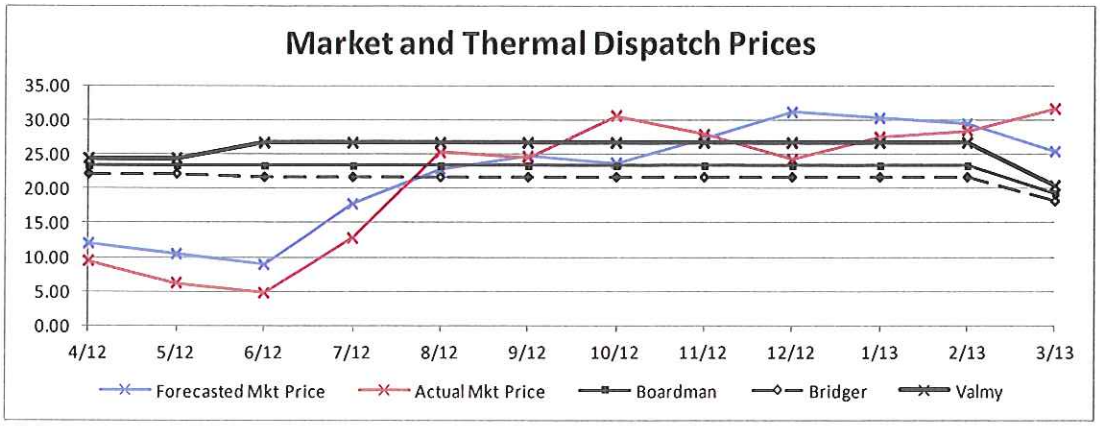
The volume of surplus sales was impacted by:

1) The availability of hydro production, and
2) weaker market prices that could not support the economic dispatch of our coal and gas resources.

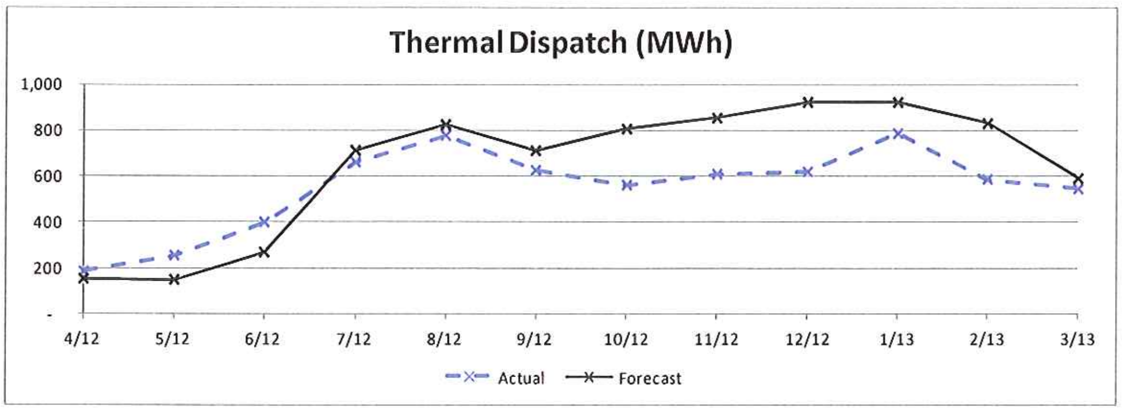
As was discussed earlier in this memo, the hydro estimate for the 2012 – 2013 water year has tended toward the low case scenario rather than the expected case. The lack of hydroelectric generation accounts for some of the low surplus sales volume.

Weaker market prices impacted Idaho Power's ability to economically dispatch its thermal facilities and also led to lower surplus sales. Forecasted market prices in the March 2012 Op Plan were at or higher than the dispatch prices of the thermal facilities for much of the PCA year. Actual market prices were lower than the forecast and were much closer to the dispatch price of the thermal units. When prices are near or below the dispatch price, off-system sales where surplus is tied to thermal generators are uneconomical.

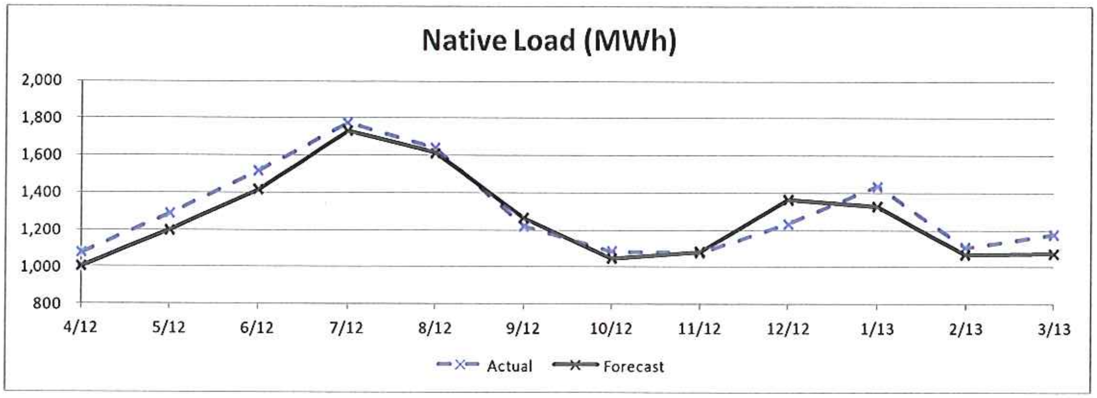
Below, the first graph shows the change between the forecast price and the actual price in relation to the dispatch prices of the coal facilities. The second graph shows the resulting impact on the generation between the forecast and actual amounts. The forecasted price from October 2012 through March 2013 is above the dispatch prices of the coal units. Therefore, the forecast included more frequent dispatch of the thermal units. As Idaho Power entered the real-time market, prices did not support the dispatch of the thermal units to the extent that the forecast had predicted.



Dispatch Prices include a $4 transmission charge.



Thermal dispatch is also greatly influenced by Idaho Power's native load and can change the amount of energy available for surplus sales. In the graph above, the disparity between forecast and actual thermal dispatch can also be explained, in part, by changes in native load. In the graph below, actual load is compared to the forecasted PCA load. The increased dispatch of thermal generation in the May and June timeframe corresponds to the increased load in those same months. The dispatch of thermal generation was also influenced by load in December and January. Warm December temperatures decreased load and thermal generation while unusually cold January temperatures increased load and thermal generation.



In summary, the following factors caused lower than projected hydro generation for the 2012-2013 PCA year:

- Warmer than normal April temperatures caused
  - reduction in flow past Milner in spring 2012 related to rapid onset of irrigation withdrawals, and
  - abbreviated Snake River Basin runoff season, with runoff occurring disproportionately during April at levels above the hydraulic capacity of Hells Canyon generators.
- Drier than normal conditions in the Snake River Basin during the snow accumulation season from December 2012 through March 2013.

Finally, surplus sales for the 2012-13 PCA year have been lower than projected primarily because of the following reasons:

- Lower than projected hydro generation as explained above.
- Lower than projected thermal generation occurring as a result of
  - lower than projected wholesale electric prices, and
  - changes in retail load.