BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO MODIFY THE ENERGY COST ADJUSTMENT MECHANISM AND INCREASE RATES BY $10.2 MILLION, OR APPROXIMATELY 3.9 PERCENT	**Case No. PAC-E-15-09** **DIRECT TESTIMONY OF MICHAEL G. WILDING**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-15-09

May 2015

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power (the "Company").

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the State of Utah. Prior to joining the Company, I was employed as an internal auditor for Intermountain Healthcare and an auditor for the Utah State Tax Commission. I have been employed by the Company since February 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Idaho Public Utilities Commission and the Wyoming Public Service Commission.

Purpose and Summary

Q. What is the purpose of your testimony?

A. My testimony supports the Company's Application to update the net power costs ("NPC") in base rates that are compared to actual NPC in the energy cost adjustment mechanism ("ECAM"). I also present and support proposed modifications to the ECAM.

Q. Please summarize the impact of the Company's proposed update to base NPC.

A. The Company proposes to update the level of base NPC in customers' rates based on the normalized NPC reported in the Company's recently-filed December 2014 Results of Operations. Total company NPC in the results of operation is $1,514 million, or $93.8 million on an Idaho-allocated basis. This compares to $1,385 million total-company, or $87.6 million Idaho-allocated, NPC currently included in base rates as a result of the 2011 general rate case[1].

Q. Will any items other than NPC be included in the update of base rates?

A. Yes. As shown Exhibit No. 3 accompanying the testimony of Ms. Joelle R. Steward, the update of $10.2 million to base rates would include updates to NPC of $2.8 million, revenue from the sale of renewable energy credits ("RECs") of $6.5 million, and renewable energy production tax credits ("PTCs") of $0.2 million. Each of these items would be subject to true-up in the annual ECAM filings. In addition to these items, base rates would include $0.7 million for the incremental amortization of the Deer Creek Mine unrecovered investment (depreciation and depletion expense), as requested in the Company's application in Case No. PAC-E-14-10. Since this amortization is a fixed annual amount, there is no need to include it in the ECAM going forward once it is included in base rates.

Q. Please summarize the Company's proposed modifications to the current ECAM.

A. The Company is proposing the following changes to the ECAM:

[1] Case No. PAC-E-11-12.

- The 90/10 percent sharing band should be eliminated, allowing for 100 percent recovery of prudently-incurred NPC;
- The calculation method should be based on retail sales at meter, eliminating the need for Staff's base rate over-collection adjustment;
- The load change adjustment rate ("LCAR") should be eliminated;
- Demand side management ("DSM") costs and sales of sulfur dioxide emission allowances ("SO_2 Sales") should no longer be tracked in the ECAM;
- PTCs should be included in the ECAM as they are closely related to NPC;
- The deferral period should be changed to correspond with the calendar year and the filing date should be changed to April 1 with rates effective June 1.

Q. Why is the Company proposing changes to the ECAM at this time?

A. The Company is filing this Application for two reasons: to implement modifications to the ECAM, and to reset base NPC along with certain other costs as an alternative to a general rate case to mitigate customers' rate impact. In the Company's last ECAM filing[2] Commission staff recommended that the Commission approve modifications to the ECAM which would align it with Staff's base rate over-collection adjustment. The Company's reply comments noted that, while it didn't oppose Staff's modification, the annual ECAM case was not the appropriate place to implement changes to the ECAM and that there were other changes to the ECAM that should be addressed. This Application creates the process to address those changes.

[2] Case No. PAC-E-15-01.

Q. Has the Company experienced changed circumstances that justify modifications to the ECAM?

A. Yes. The current ECAM was implemented July 1, 2009, and since that time there have been significant changes that justify the modifications to the ECAM proposed by the Company, including:

- The participation in an Energy Imbalance Market ("EIM") with the California Independent System Operator ("CAISO");
- The resource mix to service load has changed and the Company now relies more heavily on resources out of its control;
- A robust hedging policy has been developed in collaboration with stakeholders in states served by the Company;
- The Company has become, and will continue to be, increasingly reliant on intermittent energy to service its load; and
- The Company is not recovering its prudently incurred net power costs and no evidence has been provided in the annual ECAM's to show that the Company is not making prudent decisions or that a disallowance is required to incent the Company to make the right decisions.

Update to Base Rates

Q. Does the Company propose to update the level of base NPC included in customers' rates?

A. Yes. The Company proposes to update the level of base NPC in customers' rates using the NPC reported in the Company's recently-filed Annual Results of Operation report. Total Company NPC is $1,514 million, or $93.8 million on an

Idaho-allocated basis. This compares to $1,385 million total-company NPC, or $87.6 million Idaho-allocated, currently included in base rates. The NPC update is a $2.8 million increase to customers' rates. Exhibit No. 1 provides a detailed calculation of the updated base NPC.

Q. How was the total Company NPC amount of $1,385 million, or $87.6 million Idaho-allocated, currently included in base rates determined?

A. The current base NPC of $1,385 million, or $87.6 million Idaho-allocated was determined in the 2011 general rate case settlement. This was part of a two-step increase with the first increase effective for 2012 and the second increase, the current base NPC, was effective beginning in 2013.

Q. With that level of NPC in base rates, has the Company over- or under-collected NPC through the ECAM?

A. NPC has consistently been under recovered through base rates causing large NPC deferrals to be recovered through the ECAM. Since the 2011 general rates case, the average NPC deferral in the annual ECAM filings has been approximately $12.8 million. Given the history of under recovery through base rates, updating the NPC in base rates based on the 2014 Annual Results of Operations is a conservative increase.

Q. How are NPC calculated for the Annual Results of Operations?

A. NPC are calculated for the Annual Results of Operation report by projecting the NPC needed to serve 2014 normalized load, but incorporating known changes occurring in 2015. This is also the method most frequently used in the Company's general rate cases in Idaho. The 2015 NPC in the results of operation incorporates the latest forward market prices for natural gas and electricity, signed contracts, coal costs, and other inputs to the Company's GRID model (the production cost model) to best represent expected NPC.

Q. What are the major drivers causing base NPC to increase since it was last set in Case No. PAC-E-11-12 ("2011 GRC")?

A. The $129 million difference on a total company basis between the Base NPC set in the 2011 GRC and the proposed Base NPC from the Annual Results of Operation report is summarized in Table 1 below by the major categories in the NPC report.

Table 1

NPC Reconciliation ($millions)

	ID Base NPC
ID Base NPC 2011 GRC PAC-E-11-12	**$1,385**
Increase/(Decrease) to NPC:	
Wholesale Sales	249
Purchased Power	(82)
Coal Generation	96
Gas Generation	(73)
Wheeling Hydro and Other	12
Total Increase/(Decrease)	**$202**
Settlement Adjustment	(73)
Total Company NPC Difference	**$129**
Annual Result of Operations NPC 2015	**$1,514**

The major contributors to the variance in NPC are a reduction in wholesale sales revenue and increased coal costs. The increase in NPC due to lower wholesale sales and higher coal and gas fuel expenses is partially offset by reduced purchased power expenses. Higher load and lower wind and hydro generation also contributed to higher costs compared to Base NPC, with the impact of each spread across multiple cost categories.

The reduction in wholesale sales revenue is driven by the expiration of five long-term sales contracts and reduced revenue from short-term wholesale market sales. The drop in revenue is due to both a reduced volume of these transactions as well as a drop in the average market prices received.

There have been some notable changes that have affected coal fuel costs including contractual coal price increases, new coal contracts, and increased mine operating costs at the Bridger mine.

Q. Is the Company updating any costs, other than NPC, in the base rates?

A. Yes. The Company proposes to update revenues from the sale of RECs included in base rates. The Company also proposes to include PTCs as they are closely related to NPC. In addition, base rates would include amortization of the unrecovered plant investment of the Deer Creek Mine.

Q. What is the total increase to base rates?

A. The Company's proposed updates to base rates results in a $10.2 million, or 3.9 percent, increase to Idaho's rates. The testimony and exhibits of Ms. Steward provides details of the proposed increase by rate schedules. Ms. Steward's Exhibit No. 3 shows that the updates to NPC and REC revenues have the greatest impact, increasing rates approximately $2.8 million and $6.5 million respectively.

Q. Why is the Company proposing to update the base rates for PTCs?

A. PTCs have a direct correlation to NPC, a PTC credit is given for each megawatt-hour of production from qualifying renewable facility, meaning they rise and fall with NPC. Therefore, the Company is proposing these credits be updated in base rates and tracked in the ECAM.

Q. Please explain the proposed treatment for the Deer Creek Mine costs.

A. As reflected in the Company's application in Case No. PAC-E-14-10 the Company recently closed the Deer Creek Mine and the depreciation and depletion expenses are not included in the 2014 Annual Results of Operation NPC. The amortization of the remaining book value of the Deer Creek Mine, consisting of the depreciation expense from unrecovered plant investment should be included in base rates. Since this amortization is a fixed annual amount, there is no need to true it up in the ECAM going forward once it is included in base rates. This is consistent with the Company's application in Case No. PAC-E-14-10.

Q. Why is it appropriate to include the amortization of remaining book value of the Deer Creek Mine in base rates?

A. Prior to the Deer Creek Mine Closure the depreciation and depletion expenses were embedded in the coal costs of the Hunter and Huntington coal plants. These costs were included in both base and actual NPC and part of the ECAM. These costs however, are no longer included in actual NPC and were not included in the 2014 Annual Results of Operation NPC report. Absent this adjustment they will not be recovered through rates. Additionally, the current coal contract which replaced the Deer Creek Mine is a benefit to customers resulting in lower NPC than if the Deer Creek Mine would have remained in operation. Without updating base rates to account for the amortized remaining book value of Deer Creek Mine, customers would enjoy the benefit of the mine closure without bearing the costs.

If the amortization of the remaining book value of the Deer Creek Mine, consisting of unrecovered depreciation and depletion expenses is not included in base rates a temporary adder should be included in the ECAM to allow for the recovery of said cost until they are reflected in base rates.

Energy Cost Adjustment Mechanism

Q. Please briefly describe the Company's current ECAM as authorized by the Commission.

A. Commission Order No. 30904[3] authorized the Company to implement an ECAM, a mechanism to recover the differences between actual NPC and base NPC in rates. The current ECAM includes a 90/10 percent sharing band, meaning customers are responsible for 90 percent of the NPC differential and the Company is responsible for the other 10 percent. Other items tracked in the current ECAM to true-up the amount in base rates to actuals include: SO_2 Sales, DSM costs, and REC revenue. Various adjustments are made to the ECAM calculation including the LCAR for revenue collected for Energy-Classified Production Costs excluding NPC ("ECPC"), the Emerging Issues Task Force ("EITF") 04-6 coal cost adjustment, and Staff's base rate over-collection adjustment to account for any over- or under-collection of NPC. Beginning in 2015, the ECAM also includes a resource adder to begin recovery of the Company's investment in the new Lake Side 2 generation facility until it is reflected in customers' rates as a component of rate base.

Q. Please describe the Company's proposed modifications to the current ECAM.

A. As described above, the Company is proposing the following changes to the

[3] Case No. PAC-E-08-08.

ECAM:

- The 90/10 percent sharing band should be eliminated allowing for 100 percent recovery of prudently-incurred Idaho NPC;
- The calculation method should be based on retail sales at meter eliminating the need for the base rate over-collection adjustment;
- The LCAR should be eliminated;
- DSM costs and SO_2 sales should no longer be tracked in the ECAM;
- PTCs should be included in the ECAM as they are closely related to NPC;
- The deferral period should be aligned with the calendar year and the filing date changed to April 1 with rates effective June 1.

Q. Do NPC true-up mechanisms in other states include sharing bands?

A. Typically no. Out of all states with non-restructured power markets, only eight - Wyoming, Utah, Idaho, Oregon, Washington, Missouri, Montana, and Vermont - have sharing mechanisms built into their respective power cost true-up mechanisms.

Q. Has the recovery of NPC changed in the states within the Company's service area since the Idaho ECAM was approved in 2009?

A. Yes. At the time of Order No. 30904 the Company had a power cost true-up mechanism in place only in California. Since that time mechanisms have been implemented in Utah, Wyoming, and Oregon. The California mechanism allows for 100 percent recovery, the Wyoming and Utah mechanisms include sharing bands and the Oregon mechanism includes both dead bands and sharing bands. In March 2015, at the conclusion of the Company's most recent general rate case in

Washington, the Washington Utilities and Transportation Commission ordered that the Company must file tariffs to implement a power cost adjustment mechanism by May 31, 2015.

Q. Please describe the similarities and differences in the treatment of NPC among the Company's six jurisdictions.

A. As noted above, upon approval of a power cost adjustment mechanism in Washington, all six states in the Company's jurisdiction will provide for NPC to be recovered through a true-up mechanism. In California and Oregon, base NPC is set annually and coincides with the deferral periods. Base NPC is set during general rate cases in Wyoming and Utah and rarely coincides with the deferral period. The California mechanism does not include a sharing band, the Utah and Wyoming mechanisms have a 70/30 percent sharing band, and the Oregon mechanism has a $30 million dead band and a 90/10 percent sharing band. The Company has proposed eliminating the sharing band and including PTCs in the Wyoming ECAM as part of its current Wyoming general rate case.

Q. Is there anything unique about the Company's jurisdictions?

A. Yes. As described above, only eight states do not have a pass-through mechanism that result in full recovery of prudently incurred costs. Five of those eight are states the Company serves, so a comparison to states served by the Company is not representative of the ratemaking approach to recovery of NPC across the utility industry. The five states within the Company's service area are outliers compared to the rest of the nation in that they do not allow 100 percent recovery of NPC. By allowing full recovery of prudently incurred costs, other states have determined that a pass-through mechanism with deadbands or sharing bands is not the appropriate approach to regulate costs that are large, volatile, unpredictable, and largely outside the Company's control.

Justification for Changes

Q. Please briefly describe the EIM and why the Company's participation in the EIM warrants a change to the ECAM.

A. The EIM automates and optimizes the dispatch of resources on a least-cost basis every five minutes to serve load within reliability and transmission constraints. The EIM provides the mechanism necessary to ensure the lowest possible cost resources are utilized, obviating the need for a sharing mechanism in the ECAM. Conversely, maintaining a sharing mechanism creates the perverse impact of either limiting benefits to customers from EIM or penalizing the Company even though it is pursuing innovative solutions to reduce costs for customers. Removing the sharing mechanism ensures that customers receive the full benefits of the EIM, which further extends customer savings resulting from the diversity and opportunity in an expanded market footprint beyond the Company's borders.

Q. How has the resource mix by which the Company services its load changed since the ECAM was implemented?

A. Table 2 summarizes the generation by resource type in 2009 compared to 2013. The most drastic change is the increased reliance on short term market purchases. While this increased reliance on market purchases expands the exposure to market prices, the Company has appropriate controls in place to mitigate the potential impact to customers, including hedging natural gas and electric power to manage

NPC volatility.

Table 2

	2009		2013		Delta	
Resource Type	**GWh**	**% of Total**	**GWh**	**% of Total**	**GWh**	**% Change**
Coal	43,856	64.63%	43,698	62.38%	(158)	-0.36%
Natural Gas	8,577	12.64%	8,177	11.67%	(400)	-4.66%
Geothermal & Solar	279	0.41%	255	0.36%	(24)	-8.49%
Wind	2,063	3.04%	3,035	4.33%	973	47.15%
Hydro	3,544	5.22%	3,164	4.52%	(381)	-10.74%
Long Term Purchases and Exchanges	5,636	8.31%	5,047	7.20%	(589)	-10.45%
Short Term Purchases	918	1.35%	4,337	6.19%	3,418	372.28%
Qualifying Facilities	2,031	2.99%	2,341	3.34%	310	15.29%
Industrial Qualifying Facilities now Self-Generating	949	1.40%	0	0.00%	(949)	-99.98%
Total Resources (GWh)	**67,853**	**100%**	**70,054**	**100%**	**2,201**	**3.24%**
Total Wholesale Sales	10,616		9,395		(1,221)	-11.50%
Net System Load (GWh)	**57,237**		**60,659**		**3,422**	**5.98%**

Q. **Please briefly describe the changes to the Company's hedging policy and why it warrants a change to the ECAM.**

A. In a collaborative effort with interested parties, the Company made substantial changes to its hedging policy in 2012. Considering input from stakeholders in Utah, Wyoming, Idaho, and Oregon, the Company updated its hedging policy including guidelines that allow a reasonable percentage of the natural gas and power requirements to remain open to short-term market price exposure and allow for operational flexibility. Also, hedges are normally be limited to the short-term consistent with the Company's risk management policy to help account for relative market illiquidity and potential inaccuracy of forecasted requirements. These policy changes require the Company to maintain a specified level of exposure to natural gas and power market prices, which influences NPC volatility over which the Company has no control. The Company files detailed semi-annual hedge reports, which describe hedges transacted since the previous report as well as plans for future hedges. The policy is also subject to review by the Commission.

The changes to the Company's hedging policy warrants changes to the ECAM, specifically removing the sharing band, for two reasons: 1) The changes demonstrate the Company is actively controlling its NPC, and 2) the intended market exposure, as a result of a reliance on short term firm market purchases, is out of the Company's control.

Q. Please describe the change in the Company's reliance on intermittent energy.

A. The Company has become more reliant on intermittent energy because of the addition of QFs on the Company's system and other owned and contracted generation that serve its load. Table 2 above shows that generation from Company-owned wind and QFs has increased 47 percent and 15 percent respectively.[4]

Q. Why does the Company's reliance on intermittent energy to service its load warrant a change to the ECAM?

A. Intermittent energy is highly dependent on the weather, which is entirely out of the Company's control and causes several issues with respect to forecasting NPC in customers' rates. Company-owned wind and hydro generation provide zero-fuel-cost generation, and in the event of unfavorable weather the lost generation has to be replaced by either coal or gas generation and/or purchased on the market. There is also a correlation between weather and market prices; e.g. when

[3] The variance related to industrial customer QFs results from the customer opting to first serve its own load with its QF generation. For these Industrial QFs, in 2009 the Company bought 100 percent of the QFs' output but also serviced the customers' load. In 2013 these industrial QFs chose to service their own load first, so the Company did not receive the output from the QFs but it also did not service that portion of the customers' load.

the wind is blowing it blows for everyone in the same geographic area, which puts downward pressure on prices in nearby markets.

Unexpected changes in weather are not captured in a forecast of NPC prepared well in advance of the time the energy is actually produced and consumed. In a recent newspaper article about the accuracy of long-term weather forecasts, Louis Uccellini, director of the National Weather Service, stated, "We [the National Weather Service] sustain higher accuracy out to two to three days in advance; then it starts dropping off faster at days six through eight."[5] In fact, the National Weather Service does not make specific weather predictions more than seven days out. Under the current ECAM structure, the Company establishes base NPC months in advance of the delivery period, and any deviations from the forecast are only recovered or refunded at ninety cents on the dollar.

With regard to intermittent QFs specifically, it is important to note that the Company does not operate the QFs from which it takes energy and cannot control their generation, but is required by federal law and state regulation to purchase power from these facilities. Any increases in production from these QF is subject to the current ECAM sharing bands, under which the Company is paying 10 percent of the increased costs to the extent the QF contract price exceeds short-term market prices. These federally mandated costs should be recovered through rates without sharing.

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[4] Palmer, B. (April 15, 2013). Long-term weather forecasts are a long way from accurate. *The Washington Post*, retrieved from www.washingtonpost.com.

Sharing Bands

Q. Please describe the Company's experience with sharing bands in the current ECAM.

A. The Idaho ECAM currently includes a 90/10 percent sharing band, meaning the Company is responsible for 10 percent of the NPC variance and the other 90 percent is either paid by or refunded to customers. Since the implementation of the current ECAM, the actual operation of the mechanism has been asymmetrical with the Company consistently under recovering its costs by approximately $7 million. The sharing bands deny the Company the opportunity to recover prudent expenses even though adequate, safe, reliable electricity service has been provided.

Q. What did the Commission conclude in Order No. 30904 with regard to the sharing band?

A. The Commission found that "the symmetrical sharing band provides the Company an incentive to actively control its NPC."[6]

Q. Is the sharing band an effective incentive mechanism?

A. No. The Company believes that the sharing band provides no meaningful incentive, but it instead has historically served to penalize the Company despite prudent management and limit benefits to customers that may be achieved through the Company's efforts to reduce NPC. Despite the ineffectiveness of the sharing band as an incentive mechanism the Company has shown it has made its best efforts to control NPC. The Company's accountability to the Commission, customers and shareholders, along with the potential competition of self-

[6] Case No. PAC-E-08-08, Commission Order No. 30904 Issued September 29, 2009, page 13.

generation and direct access (available in portions of the Company's six-state service territory), provide effective incentive to minimize NPC.

Q. How has the Company demonstrated its best efforts to actively control NPC?

A. The Company has proven itself to be an industry leader by participating in an EIM with CAISO which indeed demonstrates the Company's best efforts to control NPC. EIM automates and optimizes the dispatch of resources on a least-cost basis every five minutes to serve load within reliability and transmission constraints. The Company's participation in the EIM eliminates the argument that the Company needs an outside incentive to optimize the dispatch of resources to serve customers and provides ample evidence that the Company is actively controlling its NPC.

The Company's efforts are further evident in the fact that in the six Idaho ECAM filings to this point only $1.17 million of NPC has been disallowed. This is compared to approximately $480 million of Idaho-allocated NPC incurred over the same time frame, which equates to a 0.24 percent disallowance rate. Furthermore, all of these adjustments were simply accounting issues; no costs have been disallowed based on prudence. The majority of the disallowance, $814 thousand of the $1.17 million, relates to the implementation of the back cast adjustment which was an adjustment based on the calculation of the ECAM and not the prudence of NPC.

Q. Is a sharing band an effective tool to manage and/or share risk?

A. No. Sufficient internal and external controls exist and are in place to appropriately manage risk, including the Company's Risk Management Policy, Governance and

Approvals Process, and Front Office Procedures and Practices. These policies and procedures outline the internal controls the Company has implemented and the measures taken to protect the interests of its customers and shareholders. Internal controls include hedging limits and documented management approval of hedge transactions consistent with governance requirements, system controls (logic in the natural gas and power transactions trade capture system), contract reviews and documented management approval of new contracts consistent with governance requirements. The Company must also plan to provide a least-cost, least-risk portfolio of resources, and it must operate its resources in a prudent manner. These standards apply regardless of the existence of an ECAM and/or sharing band, and consequently the sharing band has no impact on the Company's day-to-day operations.

Q. How do customers benefit from eliminating the sharing band?

A. An ECAM without a sharing band will provide more accurate price signals to customers of the cost of power. Additionally, as NPC are the largest single component of base rates, a properly designed ECAM without sharing bands mitigates the need for the Company to constantly file a GRC. This is evident in the fact that the Company has not filed a GRC in California, where there is no sharing band, since 2009. Finally, eliminating sharing bands allows customers to receive the total benefit of any cost savings that may be realized through participation in the EIM.

ECAM Calculation

Q. Please explain the current calculation of the NPC deferral in the ECAM.

A. Currently the NPC deferral is calculated monthly by comparing the Base NPC Rate ($/MWh) to the Actual NPC Rate ($/MWh) to arrive at a NPC differential rate ($/MWh). The NPC differential rate is then multiplied by the actual Idaho load at input to arrive at the NPC deferral which is then subject to the 90/10 sharing. Currently the Base NPC Rate and the Actual NPC Rate are calculated monthly using total Company NPC and total Company load at input.

Q. Please explain the proposed calculation of the NPC deferral in the ECAM.

A. The Company proposes using a similar calculation as the base rate over-collection adjustment method proposed by Commission staff[7] to calculate the NPC deferral, thus eliminating the need for the back cast adjustment. However, the Company's proposal would reflect the seasonal rates used in Idaho, and calculate the NPC Differential using sales at meter in place of load at input.

The NPC recovered through rates is calculated monthly. The first step is to determine the NPC embedded in rates (Base NPC $/MWh) for both the summer (May – October) and winter (November – April) blocks by dividing the Idaho-allocated Base NPC by the Idaho base load at the meter (i.e. Idaho retail sales) used to set rates. The Base NPC $/MWh for the appropriate block is then multiplied by the monthly Idaho actual retail sales (Actual ID Sales) during the deferral period to arrive at the monthly Idaho NPC Collected in rates.

The monthly Actual Idaho NPC is calculated by dividing total company NPC by total company Actual Sales to arrive at the monthly Actual NPC $/MWh.

[7] Case No. PAC-E-15-01, Commission Staff Comments.

The Actual NPC $/MWh is multiplied by the Actual ID Sales to arrive at the Actual ID NPC for the month.

The Idaho NPC Collected is then compared to the Actual Idaho NPC to arrive at the NPC deferral. The figure below illustrates the monthly NPC deferral calculation.

Figure 1

$$NPC\ Deferral = \left(Actual\ NPC_{\$/Mwh} \times Actual\ ID\ Sales\right) - \left(Base\ NPC_{\$/Mwh} \times Actual\ ID\ Sales\right)$$

Q. Please explain how the other components of the ECAM will be calculated under the proposed method.

A. The true-up of the LCAR (if continued), DSM costs (if continued), and revenues from the sale of RECs would be calculated using the same method as NPC, by comparing the actual collection through rates to the actual costs and/or revenues. This same method will be used to true-up PTCs. However, there would not be a seasonal rate; rather, just a single annual rate. There would be no changes to the remaining components of the ECAM: SO_2 Sales (if continued), the EITF 04-6 coal cost adjustment, and the Lake Side 2 resource adder.

Q. What are the benefits of the proposed method?

A. There are three distinct benefits of the proposed calculation: 1) by using retail sales at meter in place of load at input the ECAM is not affected by differences in actual line losses and line losses computed in base rates; 2) by using a seasonal NPC embedded in rates, the ECAM accurately reflects the revenue collected from Idaho customers that pertains to NPC; and 3) the proposed calculation eliminates the need to make an after-the-fact base rate over-collection adjustment.

Load Change Adjustment Rate

Q. Please describe the LCAR.

A. The LCAR is an adjustment to the ECAM that accounts for the collection of Energy-Classified Production Cost excluding NPC (i.e. energy-classified fixed costs from the most recent general rate case) as changes in load occur. The LCAR is calculated by comparing the Idaho base load to Idaho actual load and multiplying the difference by the LCAR rate which is currently $5.47/MWh. The Commission described the LCAR by stating, "The load growth [change] adjustment portion of the power cost adjustment mechanism removes some costs from [ECAM] recovery when loads grow and adds some costs to [ECAM] recovery when loads decline."[8]

Q. Why should the LCAR be removed from the ECAM?

A. Capital costs and other operation and maintenance costs included in the LCAR calculation do not have a similar profile to NPC; they are not highly volatile or largely outside the Company's control and therefore should not be included in the ECAM. Furthermore, the LCAR is asymmetrical in the fact that it only considers changes in loads (or sales going forward) but ignores changes in the actual underlying actual underlying energy component of production costs. This would be the equivalent of calculating the NPC deferral based only on the change in sales and failing to take into account the actual NPC incurred.

Q. What is the effect of ignoring the actual underlying ECPC fixed costs in calculating the LCAR?

A. The inherent flaw in the LCAR adjustment is that it assumes the actual ECPC

[8] Case No. GNR-E-10-03, Order No. 32206, page 6.

equals the base. These costs were set at $20.2 million as part of the 2011 GRC. In the recently-filed Annual Results of Operations, current ECPC are $23.3 million, or $3.1 million (approximately 17 percent) greater than the base set in the 2011 GRC. However, since the increase in the ECPC is not accounted for in the LCAR adjustment, the Company has refunded customers approximately $3.1 million through the LCAR adjustment in ECAMs filed since 2012.

For example, in the most recent ECAM filing the Company refunded to customers approximately $0.8 million through the LCAR adjustment. However, as noted above costs were $3.1 million above base ECPC. If actual ECPC costs would have been considered it would have resulted in a recovery of approximately $2.0 million after adjusting for load growth and sharing bands. Although correcting the LCAR adjustment would result in cost recovery, the Company is proposing to eliminate the LCAR adjustment on the basis that the ECAM was not intended to be a fixed cost adjustment mechanism, ECPC are not highly volatile or largely outside the Company's control, and the ECAM calculation already accounts for fluctuations in Idaho load.

Q. **How does the ECAM calculation capture fluctuations in Idaho load, thus mitigating the need for the LCAR?**

A. The impact of fluctuations in Idaho sales is accounted for in the ECAM calculation by comparing the Idaho NPC Collected in rates to the Actual Idaho NPC incurred. If Idaho loads increase, the Idaho NPC Collected also increases and consequently the NPC deferral would decrease. If Idaho loads decrease the Idaho NPC Collected also decreases and consequently the NPC deferral would increase.

Demand Side Management Costs and SO_2 Sales

Q. Please describe the tracking of DSM costs in the ECAM.

A. The ECAM currently tracks DSM costs by comparing actual Idaho allocated DSM costs to the Idaho allocated DSM costs in base rates. The difference is either collected from or returned to customers. The inclusion of DSM costs in the ECAM is the result of the settlement stipulation in the 2011 GRC which states: "the Parties agree that, due to the uncertainty of the jurisdictional treatment of the dispatchable irrigation load control [DSM] program currently being discussed by the MSP [Multi-State Protocol] Standing Committee, Idaho's share of the customer load control [DSM] service credit will be tracked in the ECAM."

Q. Why should the ECAM discontinue tracking DSM costs?

A. The uncertainty surrounding the MSP treatment of DSM costs is no longer an issue. MSP dictates that DSM costs are Situs assigned thus eliminating the need to track these cost in the ECAM. In addition, the Company has modified this DSM program to make it more cost effective and aligned with the benefits received.

Q. Please describe the tracking of SO_2 sales in the ECAM.

A. Revenue from sales of SO_2 emissions allowances is not included in Idaho base rates. Instead, all SO_2 sales revenue is tracked in the ECAM as an after-the-fact credit to customers.

Q. Why should the ECAM discontinue tracking SO_2 sales?

A. SO_2 sales have become immaterial. In the 2015 ECAM[9] Idaho SO_2 sales amounted to a $71 credit to customers. In 2016, the Company expects to pass

[9] Case No. PAC-E-15-01.

through a \$19 credit to customers for SO_2 sales. These sales should no longer be tracked in the ECAM, but should revert back to being included in base rates in the Company's next general rate case.

PTCs Added to the ECAM

Q. Please explain why PTCs should be included in the ECAM.

A. The generation of energy at certain company-owned facilities is eligible for the renewable electricity production tax credit under Internal Revenue Code section 45, and the credit is included as an offset to the Company's federal income taxes. For each kilowatt hour of energy generated at eligible wind-powered generating facilities the Company receives a \$0.023 credit (\$0.011 credit for eligible hydro generating facilities) on its tax return, for a duration of 10 years beginning on the date which the facility became commercially operable. The value of these credits is reflected as a reduction to current income tax expense on the financial statements and for rate making purposes.

The amount of renewable electricity production tax credit received is entirely dependent on the amount of generation at eligible facilities. The generation is highly dependent on weather, varying from year to year as weather patterns fluctuate. The forecasted generation of these facilities used to set base NPC is the same output currently used to calculate the value of the renewable electricity production tax credits in general rate cases. To the extent the generation from these plants varies from the forecast, the impact on NPC gets updated via the ECAM filings but the value of the PTC is not trued-up. Therefore, including a true-up of the PTCs in the ECAM would be appropriate.

Deferral Period and Filing Date

Q. Does the Company propose any changes to the deferral period and filing timeline of the ECAM?

A. Yes. The Company proposes changing the deferral period to correspond to the calendar year (January – December). To accommodate this change the filing date would be moved to April 1 with rates effective June 1. If the Commission approves this new deferral period the first ECAM filing after changes are effective will include a 13 month period of December to December.

Q. Have you included an example ECAM calculation that incorporates the Company's proposed changes?

A. Yes. Exhibit No. 2 includes an example ECAM calculation template with the new ECAM components included.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Case No. PAC-E-15-09
Exhibit No. 1
Witness: Michael G. Wilding

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Michael G. Wilding

May 2015

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Case No. PAC-E-15-09
Exhibit No. 2
Witness: Michael G. Wilding

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Michael G. Wilding

May 2015

Rocky Mountain Power
Exhibit No. 2 Page 1 of 1
Case No. PAC-E-15-09
Witness: Michael G. Wilding

Idaho ECAM Deferral
January 20XX through December 20XX

Line No.			May - Oct	Nov - Apr	Total
1	ID Base NPC Embedded in Rates ($	PAC-E-15-09	$ 48,116,983	45,719,457	93,836,439
2	Annual Idaho Base Load @ meter (MWh	PAC-E-15-09	1,960,121	1,523,360	3,483,480
3	NPC Rate Embedded in Base Rates ($/MWh	Line 1 / Line 2	$ 24.55	$ 30.01	$ 26.94

Line No.			Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX
	NPC													
4	NPC Rate Embedded in Base Rates ($/MWh	Line 3	$ 30.01	$ 30.01	$ 30.01	$ 30.01	$ 24.55	$ 24.55	$ 24.55	$ 24.55	$ 24.55	$ 24.55	$ 30.01	$ 30.01
5	ID Actual Sales @ Meter (MWh)													
6	ID NPC Collected in Rates ($	Line 4 x Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Total Company Adjusted Actual NPC Excl. Integration Adj.(	Adjusted Actual NPC												
8	Intra-Hour Wind Integration Cost ($/MWh													
9	Third Party Wind Sold to Wholesale (MWh													
10	Third Party Wind Adjustment ($)	Line 8 x Line 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total Company Adjusted Actual NPC ($	Line 7 - Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Total Company Sales @ Meter (MWh													
13	Actual NPC ($/MWh)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Actual ID NPC	Line 5 x Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NPC Differential $/MWh	Line 6 - Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EITF 04-6													
16	Idaho Allocated EITF 04-6 Deferral Adjustment ($		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Lakeside 2 Resource Adder													
17	Lake Side 2 Generation (MWh	Adjusted Actual NPC												
18	Resource Adder Rate ($/MWh)	PAC-E-13-04	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99
19	Total Lake Side 2 Resource Adder ($	Line 17 x Line 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Production Tax Credits (PTCs)													
20	ID Allocated PTCs in Rates ($/MWh)	PAC-E-15-09												
21	ID Actual Sales @ Meter (MWh)	Line 5												
22	ID PTCs in Rates ($)	Line 20 x Line 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	ID Allocated Actual PTCs ($)													
24	ID PTCs Deferral ($)	Line 23 - Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Total ECAM Deferral	Sum of Lines: 15, 16, 19, 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Renewable Energy Credits (REC) Revenue													
26	ID REC Revenue in Rates ($/MWh	PAC-E-15-09	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)
27	ID Actual Sales @ Meter (MWh)	Line 5	-	-	-	-	-	-	-	-	-	-	-	-
28	ID REC Revenue in Rates ($	Line 26 x Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	ID Allocated Actual REC Revenue ($													
30	**REC Revenue Adjustment ($)**	Line 29 - Line 28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Interest Rate	Order Nos. 32403, 32684												
	All Customers Balancing Account ($													
32	Beginning Balance		-	-	-	-	-	-	-	-	-	-	-	-
33	Incremental Deferral	Line 25	-	-	-	-	-	-	-	-	-	-	-	-
34	REC Revenue Adjustment	Line 30	-	-	-	-	-	-	-	-	-	-	-	-
35	Interest		-	-	-	-	-	-	-	-	-	-	-	-
36	**All Customers Deferral Balance ($)**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -