BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	**)**	
APPLICATION OF ROCKY	**)**	**CASE NO. PAC-E-12-03**
MOUNTAIN POWER FOR	**)**	
AUTHORITY TO INCREASE RATES	**)**	**Direct Testimony of Gregory N. Duvall**
BY $2.6 MILLION TO RECOVER	**)**	**Redacted**
DEFERRED NET POWER COSTS	**)**	
THROUGH THE ENERGY COST	**)**	
ADJUSTMENT MECHANISM	**)**	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-12-03

February 2012

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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from the University of Washington in 1976 and a Master of Business Administration degree from University of Portland in 1979. I was first employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the net power cost group, the load forecasting group, and the renewable compliance area.

Summary of Testimony

Q. Will you please summarize your testimony?

A. My testimony provides evidence justifying the need to add $18.1 million ("2011 Deferral") into the Energy Cost Adjustment Mechanism ("ECAM") balancing account for the 12-month period from December 1, 2010 through November 30, 2011 ("Deferral Period"). This would bring the total balance of the account to $24.1 million as of November 30, 2011. In addition, my testimony presents the

background and calculation of the Company's ECAM and describes the actual net power costs ("NPC") incurred by the Company to serve retail load during the Deferral Period.

Q. Are additional witnesses presenting testimony in this case?

A. Yes. Mr. William R. Griffith, Director, Pricing, Cost of Service & Regulatory Operations, is sponsoring testimony supporting new tariff surcharge rates for Monsanto and Agrium for inclusion in Tariff Schedule 94 with an initial collection rate of approximately $2.6 million. The existing surcharge for other customers will remain unchanged.[1] When combined with the existing surcharge rate for other customers, the Company anticipates that Schedule 94 will collect approximately $13.0 million on an annual basis as compared to the current collection rate of $10.4 million.

Q. What are the components of the $18.1 million 2011 Deferral?

A. The components of the 2011 Deferral are the customers' 90 percent share of the difference between the actual and in-rates NPC, the load growth adjustment revenue and load change adjustment revenue ("LGAR/LCAR"), the sulfur dioxide ("SO_2") allowance sales adjustment, the Emerging Issues Task Force ("EITF") 04-6 adjustment, and the renewable resource adder adjustment. Also included is 100 percent of the true-up of renewable energy credit ("REC") revenues. More specifically, the $18.1 million is made up of the following:

[1] The Company was authorized to set present Schedule 94 rates that were designed to recover approximately $12.8 million in the 2011 ECAM adjustment, Case No. PAC-E-11-07 using the Company's then-most recent general rate case test period, forecasted 12 months ending December 2010. In this current docket, the Company is using the test period, historic 12 months ending December 2010 from its most recent general rate case, Case No. PAC-E-11-12. Using this most recent test period, present Schedule 94 will collect approximately $10.4 million.

- $16.6 million is the customers' share of the NPC differential, net of the LGAR/LCAR, SO_2 sales, and EITF 04-6 deferral balance,
- $0.3 million is the renewable resource adder, and
- $1.2 million is the REC revenue adjustment.

Q. What is included in the remaining $6 million of the ECAM deferral balance that brings the total to $24.1 million?

A. The remaining $6 million of the ECAM deferral balance is made up of the following:

- $2.4 million as the second year amortization of the 2010 LGAR deferral,
- $3.6 million of uncollected balance from the Company's ECAM filing in 2011, plus interest, most of which is expected to be recovered before April 1, 2012 under the existing Schedule 94 collection rate.

Q. Based on your calculations, what is the potential amount that would be required to be collected from customers under Schedule 94 beginning April 1, 2012?

A. The combined total for potential collection from customers beginning April 1, 2012 is estimated to be $21.1 million, of which retail customers other than Monsanto and Agrium are responsible for $13.4 million, Monsanto is responsible for $7.2 million and Agrium is responsible for $0.5 million.

Q. Is the Company proposing to collect this full amount?

A. No.

Q. How much does the Company propose to collect from customers under Schedule 94 beginning April 1, 2012?

A. The Company proposes to collect $10.4 million from retail customers other than Monsanto and Agrium beginning April 1, 2012. This will require no change to the ECAM surcharge rate for theses customers. The surcharge rate for Monsanto and Agrium will be set at approximately $2.6 million to reflect the three year amortization outlined in the stipulation agreed to by the parties and approved by the Commission in the 2011 general rate case.

Q. Do you have a summary of your calculations and proposal?

A. Yes. Table 1 summarizes the Company's calculations of the ECAM balance and the proposal in this case.

Table 1

	Tariff Customers	Monsanto	Agrium	Total
NPC Differential for Deferral	10,532,075	7,460,738	576,204	18,569,017
LGAR/LCAR	(237,317)	105,158	(44,888)	(177,047)
SO2	(5,722)	(4,420)	(331)	(10,474)
EITF-06 Adjustment	68,315	21,620	2,145	92,079
	10,357,350	7,583,095	533,130	18,473,575
	90%	90%	90%	90%
Customer Responsibility	9,321,615	6,824,785	479,817	16,626,217
Renewable Resource Adder	282,851	0	0	282,851
REC Deferral	821,390	371,539	31,817	1,224,746
Total Company Recovery for NPC Deferral	**10,425,857**	**7,196,325**	**511,633**	**18,133,815**
Year 2 of LGAR ordered Amortization	**2,378,721**	**0**	**0**	**2,378,721**
Balancing Account Activity				
Prior Deferral	11,181,331	-	-	11,181,331
ECAM Revenue Collection	(7,821,058)	-	-	(7,821,058)
Interest	189,858	-	-	189,858
Estimated Undercollection @ 11/30/11	**3,550,131**	**-**	**-**	**3,550,131**
Balance Subject to Surcharge Collection	**16,354,709**	**7,196,325**	**511,633**	**24,062,667**
Tariff 94 Collection - April 2012 to March 2013	(10,450,734)	(2,409,685)	(171,269)	(13,031,688)
Tariff 94 Collection - Dec 2011 to March 2012	(3,000,000)	-	-	(3,000,000)
Balance After Estimated Collection	**2,903,975**	**4,786,640**	**340,364**	**8,030,979**
Proposed Schedule 94 Changes (Monsanto / Agrium 3 Year Amortization)		2,409,685	171,269	2,580,954

The first section of Table 1 shows the components of the $18.1 million which is summarized on the line labeled "Total Company Recovery for NPC Deferral." The next section of Table 1 shows the components of the total balance of $24.1 million as of November 30, 2011 and is labeled "Balance Subject to Surcharge Collections." The third portion of Table 1 is summarized on the line labeled "Tariff 94 Collection – April 2012 to March 2013" and shows the Company's proposed initial surcharge to Monsanto of $2.4 million, an initial surcharge to Agrium of $171,000, and a surcharge for the remaining tariff customers of $10.4 million, which represents no change to the surcharge for these tariff customers. The final section of Table 1 labeled "Balance After Estimated Collection" shows

the estimated remaining balance of the $24.1 million after the 12-month collection period ending March 31, 2013 if the Company's proposed surcharge was approved.

Q. It appears the primary driver of the $18.1 million 2011 Deferral is a result of the difference between the in-rates NPC and the actual NPC for the Deferral Period. Please explain the causes of this difference.

A. The in-rates NPC for the Deferral Period were $1.025 billion, were based on 2008 and 2010 test periods and excluded wind integration costs of about $34 million. Actual NPC for the Deferral Period were $1.344 billion, or $319 million higher than the in-rates NPC. The difference is primarily driven by a 29 percent drop in wholesale sales prices and a reduction in the volume of wholesale sales of 9.3 million megawatt-hours, or nearly 50 percent as compared to what was included in the in-rates amount. This caused a reduction in wholesale sales revenues of $505 million, offset partially by a reduction in purchased power expense of $60 million and a reduction in natural gas fuel expense of $118 million for a net increase in NPC from these three components of $327 million. Small changes in coal and wheeling expenses make up the difference.

Q. Why did sales volumes drop by 9.3 million megawatt-hours?

A. The loss of sales volume reflects the impact that low power prices had on the economics of the Company's coal and natural gas units. The Company generated 7.9 million fewer megawatt-hours from its thermal fleet than were included in rates. Table 2 shows wholesale power prices for low load hours at the Mid-Columbia and Palo Verde trading hubs as compared to the Company's average

coal costs.

Table 2

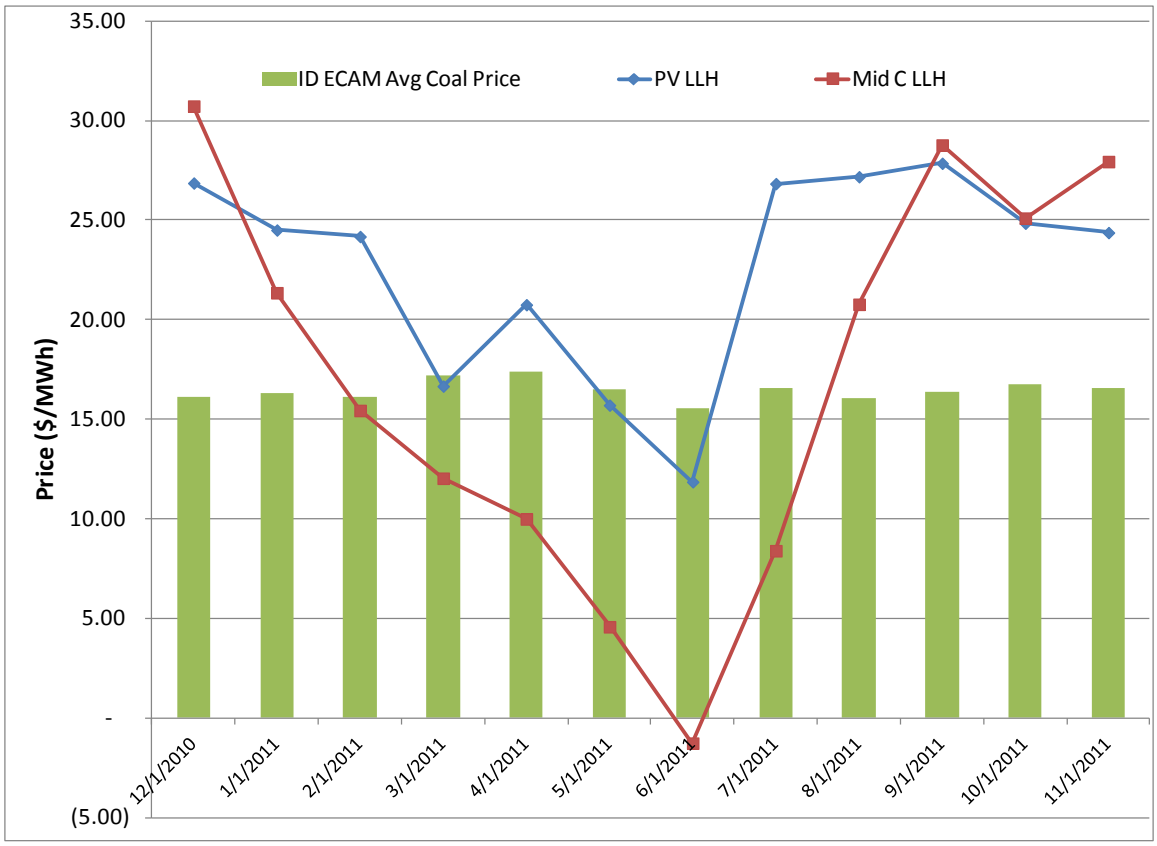

Table 2 shows that for six months in 2011, the average low load hour wholesale power prices at Mid-C were below the average coal price of the Company's coal fleet. Palo Verde low load hour wholesale power prices were below the average coal prices three months of the year. In June, the monthly average low load price was negative. These low price conditions make it uneconomic at times to run coal and gas units.

Q. Did the Company anticipate that the actual NPC for the Deferral Period would be $319 million higher than the NPC included in rates during the Deferral Period?

A. Yes. In the 2011 general rate case, I testified that NPC for calendar year 2011

would be $1.312 billion. This was not a true forecast of 2011 NPC since it used 2010 temperature adjusted loads. In Company witness Mr. J. Ted Weston's testimony filed on November 2, 2011 in support of the stipulation in the 2011 rate case, he indicated that the Company expected actual NPC for 2011 to be $1.35 billion and that the expected ECAM deferral would be in the range of $15 to $18 million. These estimates compare well to the $1.344 billion actual NPC for the Deferral Period.

Q. Why is the 2011 Deferral $18.1 million when the 2010 deferral was only $12.8 million?

A. The increase in the 2011 Deferral over the 2010 deferred amount is mainly attributable to the inclusion of Monsanto and Agrium for the first time in 2011. Their share of the deferral is $7.7 million, or 43 percent; the remaining $10.4 million is the responsibility of all other tariff customers and is actually less than the 2010 deferral for these customers.

Q. Are you sponsoring an exhibit that details the calculations of the ECAM?

A. Yes. Exhibit No. 1 presents the calculation of the ECAM.

ECAM Background

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

A. Order No. 30904 dated September 29, 2009, from Case No. PAC-E-08-08, approved the stipulation entered into by the Commission Staff, the Idaho Irrigation Pumpers Association, Monsanto and the Company that set up the structure and content of the ECAM mechanism.

In general, power cost adjustment mechanisms track and defer deviations between actual NPC and the NPC in rates. The deferred costs that accumulate over a one-year period are then passed on to customers as a rate surcharge or credit.

The ECAM Schedule 94 charge, which appears as a separate line item on customer bills, defers the difference between actual NPC incurred by the Company to serve Idaho customers over a specified period ("Actual NPC") and a base NPC level established through a general rate case proceeding ("Base NPC"). When Actual NPC is greater than Base NPC, the difference is charged to customers; conversely, where Base NPC is greater than Actual NPC, the difference is credited to customers through the ECAM.

In addition to the variance between Actual and Base NPC, the ECAM reflects the impact of the LCAR applied to the differences in actual and base period retail load, a credit for SO_2 revenues, an adjustment for the treatment of EITF 4-06 coal stripping costs and a renewable resource adder that reflects generation from new renewable resources that were not included in rates during the deferral period. Pursuant to Order No. 32196, 100 percent of the difference between base REC revenues established in a general rate case and actual REC revenues are also tracked in the ECAM. The annual deferral period for the ECAM is December 1 to November 30. The Company is required to file an application with the Commission by February 1 of each year to seek approval of the deferral amount and to adjust the ECAM rate effective April 1.

ECAM Calculation

Q. Has the ECAM calculation changed from the calculation used in the prior ECAM?

A. Yes. In the current filing, Monsanto's and Agrium's loads are included in the calculation of the ECAM balances. In the 2007 general rate case, Case No. PAC-E-07-05, the Commission approved a stipulation including electric service agreements with specific planned rate increases for Monsanto and Agrium through December 31, 2010. Beginning on January 1, 2011, those tariff contracts expired and the two customers' loads are included in the ECAM calculation in the same way as all other retail customers. However, as indicated in the stipulation Order No. 32432 in the 2011 rate case, the Company will amortize and collect Monsanto's and Agrium's share of the Commission approved 2011 ECAM balances over three years. As a result, the ECAM balances for the two customers will be tracked separately through the amortization periods.

Q. Please describe the ECAM as calculated in Exhibit No. 1.

A. This Application includes deferred amounts from December 1, 2010 to November 30, 2011. The deferral was calculated by comparing the Actual NPC to the Base NPC on a monthly basis and deferring the differences into an ECAM balancing account. During the Deferral Period, the Base NPC in rates were from two rate cases: Case No. PAC-E-08-07 ("2008 Rate Case") from December 1 to December 27, 2010, and Case No. PAC-E-10-07 ("2010 Rate Case") from December 28, 2010 through November 30, 2011. The calculation is made by utilizing the system dollar per megawatt-hour rate applied to the Idaho retail load. Exhibit No. 1

details the ECAM calculation and contains supporting information, portions of which are confidential.

Q. How are the Base NPC and Actual NPC dollar per megawatt-hour rates calculated?

A. With respect to the Base NPC rate, the Company started with the NPC of $982 million and $1,025 million approved by the Commission in Order No. 30783 from the 2008 Rate Case and Order No. 32224 from the 2010 Rate Case, respectively. Prorating the December value included in the $982 million for 27 days in December 2010 and applying corresponding months from the $1,025 million for the rest of the Deferral Period, the Base NPC for the Deferral Period are $1,028 million. The Company then divided the monthly NPC dollar amount by the monthly normalized load of the corresponding months to express the costs on a dollar per megawatt-hour basis (Exhibit No. 1, line 1). The Actual NPC rate on a dollar per megawatt-hour basis is calculated by dividing the monthly Actual NPC dollar amount by the actual monthly system load (Exhibit No. 1, line 4).

Q. Please describe how the NPC deferral is determined.

A. The deferral is calculated on a monthly basis by subtracting the Base NPC rate from the Actual NPC rate. The resulting monthly NPC rate differential (Exhibit No. 1, line 5) is then multiplied by three groups of actual Idaho retail load at input: tariff customers, Monsanto, and Agrium (Exhibit No. 1, lines 6 through 8) to calculate the NPC differential for deferral for each customer group (Exhibit No. 1, lines 10 through 13). For the 12-month period ended November 2011 the NPC differential for deferral was approximately $18.6 million before the 90 / 10

sharing.

Q. What types of costs are included in the NPC differential for deferral?

A. The NPC differential for deferral captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's production dispatch model ("GRID"). Specifically, Base NPC and Actual NPC include amounts booked to the following Federal Energy Regulatory Commission ("FERC") accounts:

- Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID
- Account 501 – Fuel, steam generation; excluding fuel handling, start up fuel[2] (gas and diesel fuel, residual disposal) and other costs that are not modeled in GRID
- Account 503 – Steam from other sources
- Account 547 – Fuel, other generation
- Account 555 – Purchased power, excluding the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable
- Account 565 – Transmission of electricity by others

Q. In addition to the comparison of Actual NPC to Base NPC, what other components are included in the ECAM?

A. There are five additional components included in the ECAM calculations: (i) LGAR revenues, which have been changed to LCAR revenues beginning April 1,

[2] Start up fuel is accounted for separately from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

2011, as authorized by the Commission in Order No. 32206, (ii) credit for any SO_2 allowance sales variances, (iii) adjustment for deferred costs associated with coal mine stripping activities recorded under the Financial Accounting Standards Board ("FASB") EITF 04-6, (iv) a renewable resource adder for 27 days in December 2010, and (v) true-up of REC revenues as authorized by the Commission in Order No. 32196.

Q. Please describe the LGAR and LCAR revenues.

A. The calculation of both LGAR and LCAR revenues is a symmetrical adjustment for any over or under collection of the Company's production related revenue requirement, excluding NPC, due to variances in Idaho load. In Order No. 32206 of Case No. GNR-E-10-03, the Commission revisited the load growth adjustment in ECAMs.

The Commission order specified five LGAR items; (1) to only include the energy classified portion of embedded production revenue requirement in the calculation, (2) that a symmetrical approach for growing and declining loads continued to be just and reasonable to both the utility and its customers, (3) to change the terminology from Load Growth Adjustment Rate to Load Change Adjustment Rate, (4) compute the LCAR based on the most recent Commission-approved cost of service results, and (5) the newly-calculated LCAR shall be used in ECAM calculations beginning on April 1, 2011.

Q. How are the LGAR and LCAR calculated and what is their impact on the 2011 Deferral?

A. In Commission Order No. 30904, the Commission approved a symmetrical

LGAR of $17.48 per megawatt-hour, which was updated to $21.89 per megawatt-hour beginning on December 28, 2010 as authorized by the Commission in the 2010 Rate Case. Beginning in April 2011, the Commission approved the LCAR, at $5.47 per megawatt-hour, which replaced the LGAR. Both the LGAR and LCAR revenues are calculated in the same manner by starting with subtracting Idaho's load at input established in rates ("Base Load" shown in Exhibit No. 1, lines 14 through 17), from actual Idaho load at input ("Actual Load" shown in Exhibit No. 1, lines 6 through 9). The difference (Exhibit No. 1, lines 18 through 21) is then multiplied by the LGAR of $17.48 per megawatt-hour for 27 days in December 2010 (Order No. 30783), $21.89 per megawatt-hour (Order No. 32196 and 32224) through March 31, 2011, and $5.47 per megawatt-hour (Order No. 32206) from April 1 through November 30, 2011 (Exhibit No. 1, line 22) to arrive at the LGAR and LCAR credits (Exhibit No. 1, lines 23 through 26) of $177,047 for the Deferral Period before the 90 / 10 sharing.

Q. How are SO_2 sales revenues included in the ECAM?

A. Line 27 of Exhibit No. 1 contains the total Company SO_2 sales revenue during the Deferral Period on a total Company basis., Line 29 of Exhibit No. 1 is Idaho's allocated share of the SO_2 sales revenue which is calculated using Idaho's System Energy ("SE") allocation factor authorized by the Commission from the 2008 Rate Case and 2010 Rate Case. The SO_2 sales revenue on line 29 of Exhibit No. 1 is credited against the NPC differential for deferral. For the Deferral Period, the total SO_2 sales revenue credit is a $10,474 reduction to the NPC deferral balance before the 90 / 10 sharing.

Q. How is the adjustment for the accounting pronouncement EITF 04-6 included in the ECAM?

A. Line 30 of Exhibit No. 1 reflects Idaho's allocated differences between excluding coal stripping costs incurred by the Company and recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal striping costs when the coal was excavated. The EITF 04-6 deferral adjustment on line 30 of Exhibit No. 1 is added to the NPC differential for deferral. For the Deferral Period, the total EITF 04-6 coal stripping deferral adjustment is a $92,079 increase to the NPC deferral balance before the 90 / 10 sharing.

Q. What is the total amount of the NPC differential and the adjustments described above?

A. Lines 39 through 41 of Exhibit No. 1 show the total NPC deferral adjusted for LGAR/LCAR revenue, SO2 revenue, and EITF 04-6 deferral for tariff customers, Monsanto and Agrium, which is approximately $18.5 million for the Deferral Period before the 90 / 10 sharing.

Q. Is the deferral subject to a sharing ratio between the Company and customers in the ECAM?

A. Yes. The ECAM includes a symmetrical sharing ratio where customers pay or receive 90 percent of the ECAM deferral balance and the Company is responsible for the remaining 10 percent. Lines 44 through 47 of Exhibit No. 1 reflect the customers' 90 percent share of the monthly deferral shown on lines 39 through 42 of Exhibit No. 1. For the Deferral Period, the customers' share of the deferred

balance is approximately $16.6 million. The remaining balance of approximately $1.8 million is not included in the deferral calculation and is not recoverable from customers.

Q. Is the deferred balance adjusted for a renewable resource adder?

A. Yes. However, the adder was only applicable to the first 27 days in December 2010 prior to the time the rates from the 2010 Rate Case went in effect. The renewable resource adder was implemented to recognize that the cost of the renewable generation resources that were not yet being recovered in Idaho rates were providing benefits to customers through the near-zero cost energy generation included in the Actual NPC. The adjustment is calculated by multiplying the authorized amount of $55.00 per megawatt-hour by the prorated actual megawatt-hour output generated in the first 27 days of December 2010 from those renewable resources that were not included in rates during the Deferral Period (Exhibit No. 1, line 48). Line 50 of Exhibit No. 1 reflects this adjustment on a total Company basis. The total Company amount is allocated to Idaho (Exhibit No. 1, line 52) based on the System Generation allocation factor ("SG"), which is further prorated to include only the tariff customers load (Exhibit No. 1, line 54). The renewable resource adder adjustment is $282,851 for the 27 days in December 2010.

Q. What is the amount of REC revenue true-up in the current filing?

A. As authorized by the Commission in Docket No. PAC-E-10-07, Order No. 32196, the Company included the difference between actual REC revenues during the Deferral Period and the amount of REC revenues included in base rates. The REC

revenue true-up included in the ECAM is symmetrical but no sharing band is applied. Thus, 100 percent of the difference between base and actual REC revenues is either refunded or surcharged to customers. Case No. PAC-10-07 established an annual level of REC revenue in base rates of $7,031,166. In the current filing, the REC revenues are prorated beginning on December 28, 2010, 27 days less than the full 12-month Deferral Period, so the amount included in base rates during the deferral period was $6.5 million. Idaho's actual REC revenues for that same time period were approximately $5.3 million, a difference of approximately $1.2 million (Exhibit No. 1, line 61).

Q. What is the total ECAM deferred balance as calculated in Exhibit No. 1?

A. The total ECAM deferred balance as of November 30, 2011 is 24.1 million and is shown on line 85 of Exhibit No. 1.

Q. How is this balance divided among customers?

A. The ECAM deferral is divided into three customer groups based on each group's actual load during the deferral period. Of the $24.1 million, $16.3 million is allocated to the tariff customers (Exhibit No. 1, Line 70), $7.2 million to Monsanto (Exhibit No. 1, Line 77) and $0.5 million to Agrium (Exhibit No. 1, Line 84). The Company will amortize and collect Monsanto's and Agrium's share of the Commission approved 2011 ECAM balance over three years pursuant to the stipulation approved by the Commission in Order No. 32432.

Q. In your opinion does the calculation of the deferred NPC adjustment in this application comply with the parameters of the Idaho ECAM as approved by the Commission?

A. Yes.

Q. Is the Company requesting a rate increase to recover the full $24.1 million deferral?

A. No. The Company estimates that approximately $3.0 million of the under collection will be recovered through Schedule 94 rates from December 1, 2011 to March 31, 2012. Any over or under collection of this amount will be addressed in future ECAM filings. Additionally, the Company is not requesting a change to the existing Schedule 94 rates for tariff standard customers at this time as it anticipates that an increase in the collection rate this year would be followed by a decrease in the rate next year. The Company is recommending that the rate be held constant for these customers in order to achieve rate stability potentially over the next two years.

Actual NPC - Base NPC Comparison

Q. How do the Actual NPC differ from the Base NPC for this Deferral Period?

A. The Base NPC approved by the Commission and included in rates is $1,028 million on a total Company basis. Total adjusted Actual NPC during the Deferral Period is $1,344 million, which is $316 million higher than what was included in rates during the Deferral Period. On a dollar per megawatt-hour basis, the Base NPC average is $17.83 per megawatt-hour, and the Actual NPC averages to $22.92 per megawatt-hour, $5.09 per megawatt-hour higher.

Q. Please explain why Actual NPC are adjusted.

A. The Actual NPC recorded on the Company's books are adjusted to remove entries that are not included in the determination of the Company's Base NPC for regulatory purposes, such as adjustments made to remove entries in months outside the current Deferral Period. In addition, Actual NPC are adjusted to reflect prior Commission approved adjustments, such as the revenue imputation of the sales contract with the Sacramento Municipal Utility District.

Q. In your summary, you indicated that several power contracts have expired. Please provide some examples of these expiring power contracts?

A. Some examples include:

- On June 30, 2011, the exchange contract between the Company and the Alcoa Power Generating Inc. for approximately 100 megawatts of capacity from the Rocky Reach project expired. Under this contract, the Company received energy during peak periods and returns energy during off-peak periods.
- On October 31, 2011, the contract between the Company and the Chelan Public Utility District for generation from the Rocky Reach project expired. Power purchased by the Company under this contract was priced at the embedded cost of the project.
- On August 31, 2011, the contract between the Company and BPA for 575 MW of capacity expired. Under this contract, the Company received energy during peak periods and returns energy during off-peak periods. In addition, power received under this contract was delivered directly to a variety of the Company's load pockets in the western area at the Company's discretion.

- On September 30, 2011, the contract between the Company and the Grant Public Utility District for displacement generation expired, which was priced at BPA's Priority Firm Power rate.
- On January 1, 2011, the amount of sales to the Public Service Company of Colorado reduces per the contract terms, which was a legacy sales contract at relatively high contract prices.

Q. You also mentioned in your summary that coal prices had increased. What are the primary drivers of the coal price increases?

A. Both third party coal purchase expense and captive mine costs have increased. The primary factors are:

- Naughton – approximately $4 million increase. Subsequent to the filing of 2010 Idaho General Rate Case, the Company amended the Naughton coal supply agreement with Chevron Mining Company. The amended coal supply agreement included advancement of the January 2011 price reopener to July 2010, changes to the contract structure and a lump sum prepayment by the Company of [redacted] million. The prepayment which is being amortized to fuel expense over the primary term of the agreement resulted in a $1.4 million increase in actual net power costs. Additionally, the contract incorporates a two-tiered pricing structure. The Base NPC included 395 thousand tons of Tier 2 coal, the lower priced tier; actual net power costs included only 337 thousand tons of Tier 2 coal. The reduction of 58 thousand tons of Tier 2 resulted in an approximately [redacted] million increase. Finally, a change in the contract price structure as well as escalation of the producer price indices

contributed to the remainder of the increase.

- Dave Johnston – approximately $6 million increase. Through 2011, the Dave Johnston plant was supplied by three mines under multi-year agreements: Peabody's Rawhide mine, Western Fuels' Dry Fork mine and Wyodak Resources' Wyodak mine. Approximately [redacted] million of the price increase at Dave Johnston plant is due to annual increases in fixed prices from the base year to 2011 with almost [redacted] million attributable to the Dry Fork mine itself. Increased rail rates during 2011 relative to what was in Base NPC have also contributed approximately [redacted] million of the total price increase at the plant.
- Hunter – approximately $14 million increase. The majority of the Hunter plant requirements are supplied under a long-term coal supply agreement with Arch Coal Sales. Arch supplied approximately 90 percent of the plant deliveries assumed in the Base NPC and approximately 75 percent during the 12 months ending November 30, 2011. Approximately [redacted] million of the $14 million increase is a result of the January 2011 price reopener under the Arch contract. As a result of the reopener, the contract price increased by almost [redacted] per ton between 2010 and 2011. The remainder of the increase at the Hunter plant is due to increased Deer Creek operating costs and a new long-term coal supply agreement with West Ridge that commenced January 2011. The reduction in Sufco deliveries from the levels included in Base NPC was offset by increase in deliveries from the West Ridge mine under the new coal supply agreement.
- Huntington – approximately $7 million increase. The majority of the Huntington plant is supplied by the Deer Creek mine. The increase is

predominantly the result of higher operating costs associated with movement of longwall operations from the Blind Canyon seam to the lower Hiawatha seam in December 2010 and reduced longwall production due to adverse geological conditions associated with elevated levels of ash and sulfur encountered in the Hiawatha seam.

- Bridger – approximately $26 million increase. The price increase at the Bridger Plant is the result of higher Bridger Coal Company production costs, [redacted] million, and increased Black Butte costs, [redacted] million. The inclusion of 378 thousand tons of Black Butte 2009 contract at a Freight-On-Board ("F.O.B") mine price of [redacted] per ton in the Base NPC versus an approximate [redacted] per ton F.O.B mine price in the actual results accounts for approximately [redacted] million of the Black Butte increase. Escalation of producer price indices under the Black Butte contract account for the remaining [redacted] million of the Black Butte increase. Higher operating costs of approximately [redacted] million at the Bridger mine in 2011 are a result of reductions in the Jim Bridger plant burn and poor underground mining conditions.

Q. Does this conclude your direct testimony?

A. Yes.