BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF AN ENERGY COST ADJUSTMENT MECHANISM (ECAM)	)))))	**CASE NO. PAC-E-08-08** **ORDER NO. 30904**

On October 23, 2008, PacifiCorp dba Rocky Mountain Power (Rocky Mountain Power; Company) filed an Application with the Idaho Public Utilities Commission (Commission) requesting approval of an energy cost adjustment mechanism (ECAM). The Company's proposed ECAM tracks annual deviations in variable power supply costs from normalized power supply costs embedded in base rates and surcharges or credits customers the accumulated balance over the subsequent year.

On November 5, 2008, the Commission issued a Notice of Application and established a November 28, 2008, intervention deadline. The parties to this proceeding are: PacifiCorp; Commission Staff; Monsanto Company; and Idaho Irrigation Pumpers Association, Inc. (IIPA), (collectively Parties). On June 29, 2009, the Parties filed an ECAM Stipulation as a proposed settlement in the case. IDAPA 31.01.01.272-276.

The Commission in this Order approves the terms of the Settlement Stipulation, authorizes an ECAM for Rocky Mountain Power and partially grants IIPA's Petition for Intervenor Funding. We find the Settlement to be fair, just and reasonable and in the public interest.

Energy Cost Adjustment Mechanism – Application

As reflected in Rocky Mountain Power's Application, net power supply costs represent a large portion of the Company's total revenue requirement and are subject to a high degree of volatility largely outside of the Company's control. Some of the factors cited by the Company causing this volatility include changes in retail load, hydro conditions, wind generation, market prices, third-party wheeling expenses, and natural gas and coal fuel expenses. Because the Company depends on both the electricity and natural gas markets to balance its system and meet load requirements, fluctuations in the markets invariably impact the Company's net power supply cost. Coal expenses, the Company states, which were previously relatively stable, are now affected by changes in commodity costs due to contract reopeners, and even the captive mine costs may change significantly in today's environment due to the rapid escalation of the costs of mining equipment and supplies. An ECAM, the Company contends, would provide safeguards to customers and give the Company an opportunity to recover the net power costs that are prudently incurred to serve those customers.

The Company notes that general rate cases in Idaho utilize historical test years with known and measurable adjustments under the Commission's rules and requirements. The use of static test period data, the Company contends, cannot accurately reflect the volatility in net power costs that the Company is currently experiencing, a variability that includes both sharp increases and decreases.

Rocky Mountain Power's proposed ECAM is designed to allow the Company to collect or credit the difference between the actual net power costs (NPC) incurred to serve customers in Idaho and the amount collected from customers in Idaho through rates set in general rate cases. On a monthly basis, the Company will compare the actual system net power costs (Actual NPC) to the net power costs embedded in rates from the most recent general rate case (Base NPC), and defer the difference in a balancing account. An ECAM rate will be calculated annually to collect from or credit to customers the accumulated balance over the subsequent year.

The ECAM is designed to recover the sum of all components of net power costs as traditionally defined in the Company's general rate cases and modeled in its power supply model GRID. The mechanism addresses only power cost expenses and does not include any costs associated with fixed cost recovery (i.e., capital investment in rate base). Specifically, Base NPC will include costs typically booked to the following Federal Energy Regulatory Commission (FERC) accounts:

> Account 447 – Sales for resale, excluding non-GRID transmission services and on-system wholesale sales
>
> Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel/gas, diesel fuel, residual disposal and other non-GRID items
> (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.)

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power, excluding BPA residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others (wheeling)

Actual costs booked to the above accounts will be subject to review by the Commission and other parties in each of the Company's applications prior to inclusion in the ECAM surcharge.

STIPULATION AND PROPOSED SETTLEMENT

On June 29, 2009, the Company, Staff, IIPA and Monsanto filed an ECAM Stipulation with the Commission as a proposed settlement of the case. IDAPA 31.01.01.272-276. The Parties contend that the Stipulation terms and conditions represent a fair, just and reasonable compromise of the issues raised in this proceeding and that the Stipulation is in the public interest. The Parties recommend that the Commission approve the Stipulation and all of its terms and conditions.

As reflected in the Stipulation and by way of background, the parties recite the following:

> On October 23, 2008, Rocky Mountain Power filed an Application ("Application") seeking approval of an Energy Cost Adjustment Mechanism ("ECAM"). Rocky Mountain Power's proposed ECAM is designed to defer the difference between Base net power costs set during a general rate case and collected from customers in their retail rates and Actual net power costs incurred by the Company to serve retail customers. The calculation of the deferral would be on a monthly basis by comparing the monthly Base net power cost ("NPC") rate in dollars per megawatt-hour to the Actual NPC rate also in dollars per megawatt-hour. The resulting monthly NPC differential rate would be applied to actual Idaho retail load to calculate the NPC differential for deferral. The net power costs of $982 million, as stipulated and approved in Rocky Mountain Power's general rate Case No. PAC-E-08-07, Order No. 30783, will be the base NPC for the ECAM until re-set in the next general rate case.
>
> The germane terms of the Stipulation are as follows:
>
> ¶4. Parties agree that the design, format and accounts of the ECAM shall be as set forth in the Company's Application in Case No. PAC-E-08-08 and as to be described in more detail by the Company in its Stipulation supporting testimony. The Parties further agree that the ECAM is to be

effective July 1, 2009, provided the Commission has issued an order approving the ECAM consistent with the terms in the Stipulation.

¶5. Parties agree that the ECAM will include a symmetrical sharing band wherein when there is a difference between Actual NPC and Base NPC, customers pay (if there is an increase in NPC) or receive (if there is a decrease in NPC) 90 percent of the difference, and the Company is responsible for the remaining 10 percent.

¶6. Parties agree that the annual deferral period to be used in the ECAM will be December 1 to November 30, and that annually, on February 1, the Company will file an application with the Commission to adjust the surcharge or surcredit ("ECAM Rate") effective April 1 each year, refunding or collecting the ECAM deferred balance from the prior deferral period.

¶7. Parties agree that a symmetrical load growth adjustment rate (LGAR) of $17.48 per MWh will be applied to the incremental load from the base load established in Case No. PAC-E-08-07, and that the LGAR and base load will be updated each time Base net power costs are updated in a general rate case.

¶8. Parties recognize that the Company has made significant investments in renewable generation projects that are not yet being recovered in Idaho rates and that these projects provide significant benefits to customers through the ECAM. Therefore from the effective date of the ECAM to the effective date of rates in the next rate case, the Parties agree that the ECAM will include a renewable generation investment offset adjustment. The adjustment recognizes that actual power costs have been reduced by power generated from these renewable generation projects, but that the costs of these projects are not yet being recovered in Idaho rates. The adjustment will be based on $55.00 per MWh, as calculated in [Settlement Stipulation] Attachment 1, multiplied by the actual MWh output generated by the renewable resources that were not included in rate base in Rocky Mountain Power's Case No. PAC-E-08-07.

¶9. Parties further agree that a carrying charge equal to the Commission-approved customer deposit rate will be applied symmetrically to the monthly ECAM deferred balance.

¶10. In the event the Company intends to seek an increase to the ECAM rate exceeding seven (7) percent, the Company agrees to meet with the Staff and interested parties to discuss the underlying drivers of such a change at least 30 days prior to filing an application with the Commission for approval of the change to the ECAM rate.

¶11. The Company agrees to work with the Parties to develop rates that reflect line losses and that distinguish transmission, primary and secondary voltage delivery service in the implementation of the ECAM rates. A technical conference will be convened by August 15, 2009 to begin discussions on a methodology and will use line loss information from the 2008 general rate case (PAC-E-08-07) as a starting point for the discussions. In the event an agreement on rate design for the ECAM rate is not reached by April 1, 2010, the ECAM rate will be applied to all schedules and customers on a flat kWh usage basis until an agreement is reached or a method is ordered by the Commission.

¶12. The Company agrees to hold a risk management hedging seminar to educate Parties about the Company's risk management practices and hedging strategies.

¶13. In recognition for and as a result of the implementation of the ECAM with an adjustment for renewable generation projects not yet in rate base as specified in [Stipulation] Paragraph 8 above, the Company agrees not to file a general rate case prior to May 1, 2010.

¶14. The Parties agree that SO2 sales made after June 30, 2009 will be included as an offset to the ECAM deferral with the same 90%/10% sharing band explained above in [Stipulation] Paragraph 5. The Parties further agree that sales made prior to such date will continue to be amortized over fifteen years consistent with current practice as reflected in Case No. PAC-E-06-04 (Larson Direct Testimony, Exh. 1, pp. 3.6 and 3.6.1.).

¶15. The Company's filed Case No. PAC-E-08-07 included an annual level of amortization of three regulatory liabilities for West Valley lease, administrative and general expense merger commitment, and the gain on the sale of the Goose Creek transmission line which reduced the revenue requirement used in establishing the current base rates. The current rates will continue until new rates are set at the end of 2010 or later and, as a result, customers continue to receive the benefit of the amortization in rates until that time. As of December 31, 2010, an unamortized balance of $156,434 for the Goose Creek sale will remain on the Company's books and records. The Parties stipulate and agree that upon Commission approval of this Stipulation the Company will credit the ECAM deferral for the Goose Creek sale in the amount of $156,434. Accordingly, the Parties agree that the Company can write off the remaining balances of the regulatory liabilities after this transfer and upon Commission approval of the Stipulation.

On July 16, 2009, the Commission issued a Notice of Stipulation and Proposed Settlement and Scheduling in Case No. PAC-E-08-08. The deadline for filing testimony in support of the Settlement Stipulation by stipulating parties was July 31, 2009. The deadline for filing written comments by the public and interested parties was August 14, 2009.

Testimony supporting the Stipulation was filed by J. Ted Weston, Manager of Idaho Regulatory Affairs for PacifiCorp dba Rocky Mountain Power; Randy Lobb, Utilities Division Administrator for Commission Staff; and Anthony J. Yankel on behalf of Idaho Irrigation Pumpers Association, Inc. Monsanto Company, although a signator to the Stipulation, filed no testimony.

Rocky Mountain Power

Supporting testimony on behalf of Rocky Mountain Power was filed by its Manager of Regulatory Affairs, J. Ted Weston. A description of the purpose of the Energy Cost Adjustment Mechanism and the accounts and types of costs that are to be included carry forward from the Company's Application to the Stipulation and Mr. Weston's testimony. Included with the Company's supporting testimony is an example of the ECAM deferral calculation. Company Exh. 4, attached. The ECAM deferral will be calculated on a monthly basis by comparing the actual system net power costs (Actual NPC) on a dollars per megawatt-hour basis to the net power costs embedded in rates from the Company's most recent general rate case (Base NPC). Actual NPC will be calculated using all components of net power costs as traditionally defined in the Company's general rate cases. The actual monthly system NPC will be divided by the system load for that month to calculate the Actual NPC dollars per megawatt-hour rate and that rate is then compared to the Base NPC rate to determine the NPC differential. The ECAM rate will be updated annually to collect from or credit to customers the accumulated balance over the subsequent year. The parties agree that the ECAM will include a symmetrical 90% (customer)/10% (Company) sharing band.

Base NPC will be determined and approved in general rate case proceedings based on total Company net power costs. Initially, a Base NPC of $982 million as stipulated to and approved in Order No. 30783 from Case No. PAC-E-08-07, the Company's most recent general rate case, will be used for the ECAM, until reset in the Company's next general rate case. The monthly net power costs from the most recent general rate case will be divided by the monthly normalized load used to determine those net power costs to express the costs on a dollar per megawatt-hour basis.

In addition to the comparison of Actual to Base net power costs, two additional components are included in the ECAM, a load growth adjustment rate (LGAR) and a credit for any SO2 allowance sales. The LGAR is a symmetrical adjustment to offset any over or under collection of the Company's production-related revenue requirement as growth-related load changes occur. The Load Growth Adjustment Rule (LGAR) is set at $17.48 per megawatt-hour (MWh) to reflect the Commission-approved production-related costs embedded in rates. The LGAR and base load will be updated each time Base NPC are updated in a general rate case. The load growth adjustment is calculated by subtracting Idaho's base load which is the load from the most recent general rate case from actual Idaho load. The difference is multiplied by the LGAR of $17.48 and the product is the load growth adjustment.

The parties agree also that SO2 sales made after June 30, 2009, will be included as an offset to the ECAM deferral. The parties further agree that sales made prior to such date will continue to be amortized over 15 years consistent with current practice as reflected in Case No. PAC-E-06-04 (Larsen Direct Testimony, Exhibit 1, pp. 3.6 and 3.6.1). Calculation of the Idaho SO2 offset is reflected in Exhibit No. 4 of the ECAM template as more particularly described in Weston supporting testimony, pp. 8-9.

The ECAM Stipulation also contains an agreement to account for the energy benefits of new renewable generation resources that are online but not yet included in base rates. Parties recognize that these projects provide significant benefits to customers through the ECAM. Therefore, from the effective date of the ECAM to the effective date of rates in the next rate case, parties agree that the ECAM will include a renewable generation investment offset adjustment (Renewable Resource Adder). The adjustment recognizes that Actual NPC have been reduced by power generated from these renewable generation projects. The adjustment will be based on $55 per megawatt-hour, as calculated in Stipulation supporting testimony Exhibit 5, multiplied by the actual megawatt-hour output generated by the renewable resources. In recognition for, and as a result of, the implementation of the ECAM with an adjustment for renewable generation projects not yet in rate base, the Company has agreed not to file a general rate case prior to May 1, 2010. This rate stability and assurance of no rate increase prior to April 1, 2010, the effective date of the ECAM rate, is another key customer benefit.

The balancing account and ECAM rates serve as a true-up mechanism to recover or credit the differences between base NPC and actual NPC. The monthly under or over recovery will accumulate in the balancing account and accrue a carrying charge equal to the Commission's most recently approved customer deposit rate. On an annual basis the accumulative deferred balance in the balancing account will be converted to a Schedule 94 ECAM rate expressed on a cents-per-kilowatt-hour basis for projected Idaho sales for the next 12 months of the ECAM recovery period.

The parties to the Stipulation recognized that the Company's filed Case No. PAC-E-08-07 included an annual level of amortization of three regulatory liabilities which reduced the revenue requirement used in establishing the current base rates, i.e., (1) the West Valley lease, (2) administrative and general expense merger commitment, and (3) the gain on the sale of the Goose Creek transmission line. The current rates will continue until new rates are set at the end of 2010 or later and as a result customers will continue to receive the benefit of the amortization in rates until that time. As of December 31, 2010, an unamortized balance of $156,434 for the Goose Creek sale will remain on the Company's books and records. The Stipulation specifies that upon Commission approval thereof, the Company will credit the ECAM deferral for the Goose Creek sales in the amount of $156,434. Accordingly, the parties agree that the Company can write off the remaining unamortized balances of these regulatory liabilities.

The Idaho tariff and tariff contract loads are separated to isolate the tariff customer share from the contract tariff customers (Monsanto and Agrium) because tariff contract loads are not subject to any ECAM surcharges/surcredits until January 1, 2011. Reference Case No. PAC-E-07-05, Order No. 30482. The tariff contract customers' loads will be included in the Idaho ECAM cost deferral calculation beginning January 1, 2011, and will be subject to the ECAM rate from that date forward. Any ECAM balance at December 31, 2010, would be isolated from the balance calculated beginning January 1, 2011, to assure these tariff contract customers have no impact on the ECAM deferral prior to the end of the service agreement.

The ECAM deferral period will be December 1 through November 30. An annual application to adjust the ECAM rate will be filed with the Commission on February 1. Parties and Commission Staff would then review the application, and assuming the application is approved, the ECAM rate would then be updated and effective April 1. The initial deferral period for the first year of the ECAM will be July 1 through November 30, 2009.

The Company is working with other parties to the Stipulation to design rates that reflect line losses and distinguish between transmission, primary and secondary voltage delivery service. The Company also agrees to hold a risk management hedging seminar to educate parties about the Company's risk management practices and hedging strategies.

Commission Staff

Supporting testimony on behalf of Commission Staff was filed by Randy Lobb, Utilities Division Administrator. Mr. Lobb states that the proposed ECAM in this case is very similar to the Power Cost Adjustment (PCA) mechanisms approved by the Commission for Idaho Power Company and Avista Corporation. The mechanism tracks four primary power supply accounts: (1) Generation fuel expense, (2) Market purchase power expense, (3) Surplus energy sales revenue, and (4) Variable transmission expense.

Staff supports the Settlement establishing the ECAM because, Staff contends, it is now equitable to do so and as designed reasonably balances the interest of PacifiCorp (Rocky Mountain Power) shareholders and Idaho retail customers. PacifiCorp's resource portfolio, Staff notes, has expanded to include a much larger portion of natural gas-fired generation. The Company's portfolio also consists of 30% hydropower and increased wind generation. Given the variability of hydro-generation and wind generation along with the volatility in natural gas and electric market prices, Staff believes the Company's variable power supply cost exposure is similar to that of other electric utilities that have Power Cost Adjustment (PCA) mechanisms in Idaho.

In addition to customers benefiting when variable power supply costs are less than normalized costs included in base rates, Staff believes that the ECAM could have customer benefits even if variable power supply costs are above normal. For example, more timely recovery of variable power supply costs between rate cases may reduce the frequency of general rate cases. It may also reduce the need for a forecasted test year in general rate case filings. Finally, as more of PacifiCorp's state jurisdictions adopt ECAMs, borrowing costs should decline even in the face of increased infrastructure and investment.

Staff in its supporting comments cites the similarities and differences between the existing PCA mechanisms of Avista and Idaho Power. Many of the proposed ECAM terms, it states, are identical. For example, the mechanism compares base net power costs for the same expense and revenue accounts established in the utility's last rate case to actual net power costs incurred on a monthly basis. Like Avista's PCA, the difference is then accumulated in a deferral account with interest at the customer deposit rate for true-up once a year.

The proposed ECAM also contains a load growth adjustment calculated in a manner similar to that of existing PCAs. Once the deferral amount is known, it is spread over the expected annual energy consumption for the next year. Any deferred amount over- or under-recovered remains in the deferral account for subsequent true-up during the next ECAM period. Finally, the mechanism contains a 90%/10% sharing percentage as does the Avista PCA to align the interest of the Company and its customers and assure that power supply costs are as cost-effective as possible.

While there are similarities, Staff notes that there are also differences. For example, the comparison between base power supply costs and actual power supply costs is made on a cost per kilowatt-hour basis. Staff believes that comparing power supply costs on a kilowatt-hour basis reduces the effect of load growth and limits the necessary size of the load growth adjustment.

The proposed ECAM also contains two elements of a temporary nature. The first element is that the ECAM will apply only to Idaho tariff customers because Nu-West (or Agrium) and Monsanto are served under special contracts approved by the Commission through 2010. (Duvall Direct, pp. 8-9.) Staff supports the exclusion noting that any Idaho jurisdictional power supply costs subject to recovery (or disbursement) through the ECAM will be prorated to remove power supply costs associated with special contract loads. The other temporary provision is the Renewable Resource Adder, ¶ 8. This adjustment will be made to actual ECAM power supply costs until completion of the new general rate case.

With the assistance of the Company, Staff performed an analysis with a backcast to estimate the effect of the ECAM on the Company's Idaho rates for the period January through May 2009. Company Exh. 4, attached. The backcast showed the components of the ECAM and the amounts that accumulated over the five-month period. It showed that the single largest deferral component was the Renewable Resource Adder. The Renewable Resource Adder is a temporary ECAM component that allows the Company to recover the fixed costs of new wind generation until those costs are included in base rates in the Company's next general rate case. The Renewable Resource Adder is an appropriate ECAM cost, Staff contends, because the power supply cost benefits of new wind generation are automatically captured in the ECAM.

New wind generation reduces fuel costs and purchased power costs and increases secondary sales revenues. Requiring the shareholders to pay the fixed costs while passing nearly all the benefits on to customers, Staff contends, is an inequitable ratemaking practice. The second largest ECAM component was the net power cost deferral. The other two ECAM components were SO2 credits and interest. If the backcast level of deferral continued for 12 months the deferral amount would be approximately $2.6 million. The Company's current approved annual revenue requirement for tariffed customers is $147.8 million. The rate increase would be about 1.8%. The Company's actual power supply costs, Staff notes, may vary significantly from year to year.

Idaho Irrigation Pumpers Association, Inc.

Supporting testimony for the IIPA was submitted by Anthony J. Yankel. IIPA notes that the ECAM proposed in Idaho is different from the energy cost adjustment mechanisms of the Company in its other jurisdictional states. Although it seems somewhat of an administrative burden for the Company to have four or five different power cost adjustment clauses, IIPA states that each Commission is thus able to have a power cost adjustment mechanism that fits its own unique circumstances and requirements. IIPA contends that it is appropriate to have an ECAM where a utility sells and/or buys a great deal of energy in the market, and where market prices can widely fluctuate. An energy cost adjustment mechanism may be of value in adjusting the utility's rates on more of a real time basis in order to follow costs that are being incurred on the system. This is generally the case with PacifiCorp, IIPA contends, where a large percentage of the Company's load is served by not only its own generation, but by purchased power as well, while at the same time, the Company also sells a great deal of power into the markets.

Commenting on the variance in the Company's net power costs over the last few years, IIPA states that in the Company's 2007 general rate case the Company filed for a test year net power cost of approximately $862 million. In the 2008 general rate case it filed for a test year net power cost that was $120 million greater or $982 million. Its actual new power costs for the 12 months ended December 31, 2008, were $118 million greater than the 2008 test amount, or $1.1 billion.

IIPA notes that the symmetrical sharing band for Idaho Power recently raised from 90% up to 95%. IIPA contends that this is appropriate because Idaho Power and Rocky Mountain Power are not the same. Idaho Power has to function in the same volatile energy market as does the Company, but Idaho Power has the additional volatility of being a predominantly hydro system. For now, IIPA states, a 90% sharing mechanism is more appropriate for Rocky Mountain Power than a 95% sharing mechanism.

IIPA states that a stay-out provision preventing the Company from filing a general rate case prior to May 1, 2010 was not just an important element of the Stipulation – rather without this provision, IIPA states any offer by the Company would have been a no starter. That being said, the Irrigators note that irrigators saw also the reasonableness of including a renewable generation investment offset adjustment to recognize the Company's lease investment in wind generation.

One other major issue in which the Irrigators took particular interest pertained to the Company's original proposal to treat all sales the same on a kilowatt-hour basis by adding any surcharge or refund to customers on an equal cents-per-kilowatt-hour basis as a result of the ECAM. The Irrigators (as well as Monsanto Company) took the position that such treatment is in contrast to the way costs are incurred, rates are designed, and costs are allocated. It is a well accepted premise, the Irrigators contend, that a kilowatt-hour for sale at the secondary distribution level is not equivalent to a kilowatt-hour for sale at the primary distribution or transmission level. There are losses involved, with more losses taking place at the secondary level than at the primary or transmission level. If the Company incurs fewer losses to serve a primary or a transmission customer than it does to serve a customer on the secondary distribution system, then the Irrigators contend that those customers should not pay the same rate for the ECAM adjustment. Losses are built into the cost of fuel, purchase power, etc., found in base rates, and Irrigators contend they should also be incorporated into the ECAM adjustment. Although the Stipulation does not specifically calculate the impact of losses on the ECAM adjustment, the parties have committed to working together to develop such a rate/procedure. If an appropriate procedure cannot be developed, the matter will be brought to the Commission's attention.

Commission Findings

The Commission has reviewed and considered the filings of record in Case No. PAC-E-08-08 including the initial Application and supporting testimony of Greg Duvall, Director of Long Range Planning and Net Power Costs. We have also reviewed and considered the Stipulation (and proposed settlement) and supporting testimonies filed on behalf of the

Company, the Irrigators, and Commission Staff. IDAPA 31.01.01.274-276. Settlements are reviewed under Commission Rules of Procedure 274-276. We incorporate by reference the submitted Stipulation (and proposed settlement) as if set forth herein in its entirety.

As reflected in the Commission's Rules, the Commission is not bound by any settlement reached by the parties. RP 276. Proponents of a proposed settlement carry the burden of showing that the settlement is reasonable, in the public interest, or otherwise in accordance with law or regulatory policy. RP 275. The Commission is to independently review any settlement proposed to determine whether the settlement is just, fair and reasonable, in the public interest, or otherwise in accordance with law or regulatory policy. The Commission may accept the settlement, reject the settlement or state additional conditions under which the settlement will be accepted. RP 276.

We find that the Stipulation represents a fair, just and reasonable compromise of the issues presented in this case and that the Stipulation parties provide justification for authorizing an ECAM for Rocky Mountain Power in Idaho. We find that approval of an ECAM is supported by the volatility in the energy market and the changing character of the Company's resource portfolio. Our comfort with the proposed ECAM of Rocky Mountain Power is strengthened by our experience with the PCA mechanisms of Idaho Power and Avista. The proposed ECAM contains a symmetrical 90/10 sharing band, a load-growth adjustment, a credit for SO2 sales, and an interest multiplier for deferrals, each component contributing to the overall fairness of the mechanism. We find the temporary inclusion of a renewable resource adder, the write-off of specific regulatory liabilities and the exclusion of tariff contract loads to be reasonable implementation adjustments. We find that customers will benefit from the Company's commitment not to file a general rate case before May 1, 2010, and its agreements to work with parties to design ECAM rates that reflect line losses and distinguish between transmission, primary and secondary voltage delivery service and to conduct a risk management hedging seminar.

The Commission finds that the designed ECAM will send better price signals to the Company's customers of the cost of power by adjusting their rates on a more current basis. The symmetrical sharing band provides the Company an incentive to actively control its net power costs. We find the agreed July 1, 2009, date for initial recording of power supply cost deferrals to be reasonable. We also find that the annual ECAM filings will provide an opportunity for interested parties to review and provide input on one of the Company's main cost drivers.

PETITION FOR INTERVENOR FUNDING

A Petition for Intervenor Funding in this case was filed by the Idaho Irrigation Pumpers Association, Inc. in the amount of $22,157.24 (consisting of $17,849.14 consultant fees (135 hours at $125 per hour and $974.14 postage and travel) and $4,308.10 legal fees (20.30 hours at $185 per hour, 3 hours at $135 per hour and $147.60 postage and travel)).

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules of Procedure 161-165. Section 61-617A(1) declares that it is "the policy of [Idaho] to encourage participation at all stages of all proceedings before this commission so that all affected customers receive full and fair representation in those proceedings." The statutory cap for intervenor funding that can be awarded in any one case is $40,000. *Idaho Code* § 61-617A(2). Accordingly, the Commission may order any regulated utility with intrastate annual revenues exceeding $3.5 million to pay all or a portion of the costs of one or more parties for legal fees, witness fees and reproduction costs not to exceed a total for all intervening parties combined of $40,000.

Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a Petition for Intervenor Funding. The petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared.

IIPA, a participant in settlement discussions and a signatory to the Stipulation, urges the Commission to adopt the terms of the Stipulation. Although this case resulted in settlement, IIPA contends that it had to prepare as though it was a fully contested case. The expenses and costs that IIPA seeks to recover were incurred, it states, in corresponding and collaborating with all the parties, and in gathering information, drafting and reviewing documentation and testimony, and negotiating changes to the Stipulation language.

IIPA represents that to support activities the organization relies solely upon dues and contributions voluntarily paid by members and intervenor funding. Member contributions, it states, have been falling, presumably due to the current depressed economy, increased operating costs and the threats related to water right protection issues. IIPA represents that the costs incurred for participating in this case constitute a financial hardship for the organization.

IIPA contends that it provided a unique perspective on a number of issues in this case, i.e., (1) the "stay out" provision (¶ 13) and the temporary inclusion of a negotiated dollar amount ($55/MWh) to provide the Company some recovery of its investment in renewable generation projects (¶ 8); and (2) on the issue of line losses and the distinction of taking service at the primary, transmission and secondary level in determining how to spread ECAM adjustments in the future (¶ 11).

IIPA, appearing on behalf of the irrigation class of customers under Schedule 24, contends that its participation in the settlement discussions on the above two issues was a benefit to all customer classes.

Commission Findings

Submitted for Commission decision in this case is a Petition for Intervenor Funding filed by the Idaho Irrigation Pumpers Association ($22,157.24). The Commission has reviewed the Petition and the record of proceedings.

Intervenor funding is available pursuant to *Idaho Code* § 61-617A (Award of Costs of Intervention) and the Commission Rules of Procedure 161-165. Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for petitions for intervenor funding.

Pursuant to *Idaho Code* § 61-617A(2), the Commission may order Rocky Mountain Power to pay all or a portion of the costs of one or more parties for legal fees, witness fees, and reproduction costs, not to exceed a total for all intervening parties combined of $40,000 in any proceeding before the Commission. The total amount requested by the Irrigators is $22,157.24.

Idaho Code § 61-617A includes a statement of policy to encourage participation by intervenors at all stages of all proceedings before the Commission. The Commission determines an award for intervenor funding based on the following considerations:

(a) A finding that the participation of the intervenor has materially contributed to the decision rendered by the Commission; and

(b) A finding that the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor; and

(c) The recommendation made by the intervenor differed materially from the testimony and exhibits of the Commission Staff; and

(d) The testimony and participation of the intervenor addressed issues of concern to the general body of users or consumers.

Idaho Code § 61-617A.

We find that the Petition for Intervenor Funding in this case was timely filed and satisfies all of the "procedural" and technical requirements set forth in the Commission's Rules of Procedure and *Idaho Code* § 61-617A.

In this case the Commission finds it reasonable to award the Irrigators their out-of-pocket costs ($1,121.74) and a discounted amount for consultant and attorney fees. We do not feel compelled to grant the full amount requested. In making an adjustment to IIPA's requested intervenor funding amount in this case, we considered the nature of the proceedings, the filings of record and the respective participation and contributions of Commission Staff and the Irrigators to the Commission's decision. While we are able to recognize the Irrigators' contribution regarding the issue of line losses and level of service, we find little material difference in its other recommendations from those of Staff. We award the Irrigators $16,898.74 and find such award to be fair, just and reasonable. IIPA is a non-profit corporation representing farm interests and relies solely upon dues and contributions voluntarily paid by members based on acres irrigated or horsepower per pump. We appreciate the participation of the Irrigators in this case and recognize their contribution to the ultimate resolution of issues.

The Commission finds that the intervenor funding award to the Irrigators is fair and reasonable and will further the purpose of encouraging "participation at all stages of all proceedings before the Commission so that all affected customers receive full and fair representation in those proceedings." *Idaho Code* § 61-617A(1).

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Rocky Mountain Power, an electric utility, and the issues presented in Case No. PAC-E-08-08 pursuant to Idaho Code, Title 61, and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

O R D E R

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission hereby approves the terms of the Settlement Stipulation offered in this case, and in so doing approves an Energy Cost Adjustment Mechanism for Rocky Mountain Power in Idaho. The Company is directed to file a Schedule 94 tariff comporting with this Order.

IT IS FURTHER ORDERED and the Idaho Irrigation Pumpers Association, Inc.'s Petition for Intervenor Funding is partially granted in the amount of $16,898.74. Reference *Idaho Code* § 61-617A. Rocky Mountain Power is directed to pay said amount to the Irrigators within 28 days from the date of this Order. IDAPA 31.01.01.165.02. The Company shall include the cost of this award of intervenor funding to the Irrigators as an expense to be recovered in the Company's next general rate case proceeding from irrigation customer class. *Idaho Code* § 61-617A(3).

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 29th day of September 2009.

JIM D. KEMPTON, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:PAC-E-08-08_sw3

Rocky Mountain Power
Exhibit No. 4 Page 1 of 1
Case No. PAC-E-08-08
Witness: J. Ted Weston

Idaho ECAM Deferral (PAC-E-08-08)

Line No.			Jan-09	Feb-09	Mar-09	Apr-09	May-09
1	Base NPC Rate ($/MWh) - See footnote #1 below		14.48	13.89	11.44	18.23	15.93
2	Total Company Adjusted Actual NPC ($)		72,935,924	72,605,090	69,405,416	68,614,088	75,450,101
3	Actual Retail Load (MWh)		5,255,917	4,579,857	4,700,251	4,254,657	4,424,642
4	Actual NPC ($/MWh)	Line 4 = Line 2 / Line 3	13.88	15.85	14.77	16.13	17.05
5	NPC Differential $/MWh	Line 5 = Line 4 - Line 1	(0.60)	1.96	3.32	(2.10)	1.13
6	Actual Idaho Tariff Load (MWh)		160,260	137,083	132,778	116,526	189,202
7	Actual Idaho Tariff Contract Load (MWh) - See footnote #2 below						
8	**NPC Differential for Deferral ($)**	Line 8 = Line 5 * Lines 6+7	**(95,981)**	**269,163**	**441,421**	**(244,989)**	**213,204**
9	Base Load - (1) See footnote below		147,983	135,627	134,939	112,794	194,884
10	Difference Base Load to Actual Load	Line 10 = Line 6 + Line 7 - Line 9	12,277	1,456	(2,161)	3,732	(5,682)
11	Load Growth Adjustment Rate ($/MWH)		$17.48	$17.48	$17.48	$17.48	$17.48
12	**Load Growth Adjustment Revenues**	Line 12 = Line 10 x Line 11	**(214,600)**	**(25,444)**	**37,767**	**(65,239)**	**99,328**
13	SO2 Allowances Sales		(194,500)	0	0	(173,141)	0
14	Idaho SE Factor		6.5865%	6.5865%	6.5865%	6.5865%	6.5865%
15	Idaho Allocation	Line 15 = Line 13 x Line 14	(12,811)	0	0	(11,404)	0
16	Idaho Tariff Customers Percent		57.9757%	54.1625%	56.1032%	55.5323%	70.5349%
17	**Idaho SO2 Offset**	Line 17 = Line 15 x Line 16	**(7,427)**	**0**	**0**	**(6,333)**	**0**
18	**Total NPC Differential + LGA + SO2**	Line 18 = Line 8 + Line 12 + Line 17	**(318,008)**	**243,719**	**479,189**	**(316,560)**	**312,532**
19	Customer / Company Sharing ratio		90.00%	90.00%	90.00%	90.00%	90.00%
20	**Customer / Company Sharing (90/10)**	Line 20 = Line 18 x Line 19	**(286,207)**	**219,347**	**431,270**	**(284,904)**	**281,279**
21	Renewables Generation (MWhs)		57,331	92,104	94,253	55,653	64,961
22	Renewable Adder Rate per MWh		$55.00	$55.00	$55.00	$55.00	$55.00
23	Total Renewable Resources Adder	Line 23 = Line 21 x Line 22	3,153,205	5,065,720	5,183,915	3,060,915	3,572,855
24	Idaho SG Factor		6.0479%	6.0479%	6.0479%	6.0479%	6.0479%
25	Idaho Allocation	Line 25 = Line 23 x Line 24	190,703	306,370	313,518	185,121	216,083
26	Idaho Tariff Customers Percent		57.9757%	54.1625%	56.1032%	55.5323%	70.5349%
27	**Renewable Resources Adder**	Line 27 = Line 25 x Line 26	**110,561**	**165,937**	**175,894**	**102,802**	**152,414**
28	**Recovery of Deferred Balances**						
29	Deferred Balance ($)	Line 29 = Line 31					
30	Projected Retail Sales (MWh)						
31	ECAM Surcharge Rate ($/MWh)	Line 31 = Line 29 / Line 30					
32	Actual Idaho Tariff Sales (MWh)						
33	Actual Tariff Contract Sales (MWh)						
34	**Recovery of Deferral ($)**	Line 34 = Line 31 * Lines 32+33					
35	**Balancing Account ($)**						
36	Beginning Balance			(175,793)	209,520	817,539	636,647
37	Incremental Deferral		(286,207)	219,347	431,270	(284,904)	281,279
26	Renewable Resources Adder		110,561	165,937	175,894	102,802	152,414
27	Recovery Adjustment	Line 27 = -Line 34					
29	Regulatory Liability Write-off (Un-Amortized Balance at Jan 2010)						
30	Interest		(146)	28	855	1,211	1,422
31	**Ending Balance ($)**		**(175,793)**	**209,520**	**817,539**	**636,647**	**1,071,763**
32	Interest Rate		2.00%	2.00%	2.00%	2.00%	2.00%

(1) Base NPC Rate and Load from Case No. PAC-E-08-07 $982 million
(2) Customers served under tariff contracts 400 and 401 are not impacted by the ECAM until January 1, 2011.

ATTACHMENT
ORDER NO. 30904
CASE NO. PAC-E-08-08