BEFORE THE

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UTILITIES COMMISSION

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IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)	**CASE NO. PAC-E-10-07**

DIRECT TESTIMONY OF BRYAN LANSPERY

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 14, 2010

Q. Please state your name and address for the record.

A. My name is Bryan Lanspery and my business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a utilities rate analyst.

Q. Please give a brief description of your educational background and experience.

A. I received a Bachelor of Arts degree in Economics with a social science emphasis from Boise State University in 2003. I also earned a minor in Geographic Information Systems from Boise State University in the same timeframe. I received a Master of Arts in Economics from Washington State University in 2005. My Masters work emphasized Labor Economics and Quantitative Econometric Analysis. Concurrent to pursuing my Masters degree, I functioned as an instructor of Introductory and Intermediate Economics as well as Labor Economics.

Q. Would you describe your duties with the Commission?

A. I was hired by the Commission in late 2005 as a utilities analyst. As such, my duties revolve around statistical and technical analysis of Company filings, including cost/benefit analysis, resource evaluation, price forecasting, and weather normalization methods. I have participated in several general rate cases, focusing on power supply, cost of service, and rate design. I have also been actively engaged in integrated resource planning, DSM/energy efficiency program evaluation, and revenue allocation issues. I completed the Practical Skills for the Electric Industry held by New Mexico State University in 2006, among numerous other conferences.

Q. What is the purpose of your testimony?

A. My testimony will discuss the Company's filed net power supply expenses, describe why Staff believes it is too high, and offer a recommendation that Staff believes reasonably reflects the Company's net power costs for the pro forma test year. I will also address rate design, and provide recommendations that Staff believes reflect a balanced approach to revenue recovery and sending appropriate price signals to customers.

Q. Could you please summarize Staff's position regarding net power supply expenses?

A. Yes. The Company filing indicates an increase in net power costs of $87.7 million to $1.07 billion on a system-wide basis since the 2008 general rate case. This results in an additional $3.1 million above what is currently reflected in Idaho rates. I believe a more representative net power cost figure for the Company's test year is $1.03 billion, which represents an increase over current base power supply expenses for Idaho customers of $454,000 dollars.

Q. Could you please summarize Staff's position regarding rate design?

A. Yes. Staff maintains that rate design should be based on sending cost-based price signals that promote efficient consumption of energy. While the Company does propose a tiered rate design for residential customers as directed by the Commission, I do not believe it sufficiently promotes conservation and energy efficient consumption. Staff proposes implementing a two-tiered residential rate design with different rate blocks for both summer and winter rather than year round rate blocks as proposed by the Company.

Net Power Supply

Q. Have you reviewed the Company's net power supply filing?

A. Yes, I have reviewed the Company's recommendations on power supply outlined in Company witness Shu's testimony, as well as the supporting exhibits and documentation. I have also examined the Company's GRID model, which provides the Company's calculation of net power supply.

Q. What is Rocky Mountain Power recommending as the net power supply cost to be included in its revenue requirement?

A. Rocky Mountain Power is recommending a net power supply cost of $1.07 billion on a system basis, up from $982 million included in the last general rate case. On an Idaho basis, this equates to an increase from $66.1 million to $69.2 million, or a $3.1 million increase.

Q. Do you accept the power supply costs proposed made by the Company?

A. No, I do not. I believe the Company's recommendation is too high for a number of reasons, the most important being the inclusion of wind integration costs totaling over $34 million on a system basis.

Q. Why does the Company believe wind integration costs should be included in net power supply expenses?

A. According to Company witness Shu's testimony, aside from two wind projects located in BPA's control area, the wind integration charge serves as a proxy for the variable costs incurred to integrate intermittent wind resources into the Company's resource portfolio.

Q. What value does the Company use for a wind integration cost?

A. The Company uses a value of $6.50 per MWh of wind generation. This is based on the level approved by the Commission in Case No. PAC-E-09-07 for setting published avoided cost rates.

Q. You do not think it is reasonable for the Company to include this rate in its net power cost filing?

A. No, I do not. The wind integration charge approved by the Commission is used as an adjustment to published avoided cost for mandatory purchases from qualifying wind generation facilities under PURPA. [Just approved 2 contracts for Windland.]

Q. Do you believe Rocky Mountain Power should include the wind integration charge as a variable cost to its own wind facilities and power purchase contracts?

A. No, I do not, for several reasons. First of all, these are internal costs that are neither paid under contract or to any other utility. The assumption is that wind causes the power system to operate in a less than optimal fashion due to its variability. That may be the case, but I believe that the Company's filing already reflects integration costs.

Q. How so?

A. For wind resources in service during the 2009 test year, wind integration costs are captured in actual test year expenses. This is reflected in a number of accounts, such as purchases and sales, along with fuel burning expenses. These costs simply are not part of the GRID modeling for the pro forma test year.

Q. Do you believe that wind integration costs should be included for the pro forma test year?

A. No. There is no basis to explicitly add these costs into the rate case since estimates are neither accurate nor predictable.

Furthermore, Rocky Mountain Power has an energy cost adjustment mechanism (ECAM). According to the Company, the ECAM was designed to capture the volatility in net power costs due to, among other things, wind variability (see Duval's testimony in Case No. PAC-E-08-08). The actual costs of wind variability, both on the Company's system and to the extent it provides sales opportunities outside the system, will be captured in the ECAM.

Q. Has the Commission granted wind integration costs to any other utilities in its jurisdiction?

A. No. The Commission has never expressly approved wind integration costs as part of base power supply expense for the purposes of setting base rates in any utility's general rate case.

Q. What is the impact to net power supply expense of removing wind integration costs?

A. Removing all but the wind integration costs paid to BPA reduces the net power supply expense by approximately $34 million on a system basis.

Q. Do you have any further adjustments to the Company's power supply filing?

A. Yes. During the course of reviewing recent rate case proceedings in other jurisdictions, it became apparent that there are a number of inconsistencies in the Company's power supply modeling.

Q. Do you have specific examples?

A. Yes, there are three that I have incorporated into Staff's net power cost calculation.

Q. What is the first?

A. The first is a pair of supplemental purchase contracts that Rocky Mountain Power has in its GRID model, labeled 'APS Supplemental Purchase Coal' and 'APS Supplemental Purchase Other'. The GRID model selects these resources even though it is uneconomic to do so. It is my understanding that these contracts are not considered 'must take', and excluding both from the model results in a lower net power supply.

Q. What is the reduction in net power supply calculated by the GRID model if these contracts are not included?

A. Exclusion of the contracts results in a reduction of $1.9 million on a system basis. I include this adjustment in Staff's net power cost recommendation.

Q. What is the second modeling inconsistency you have incorporated?

A. The second inconsistency involves the modeling of non-firm transmission in GRID. As noted in recent PacifiCorp rate case proceedings in other jurisdictions, and confirmed in the Company's response to Monsanto Data Requests 2.50 and 2.52, a level of non-firm transmission contracts and Company-owned assets used by the Company to optimize its system have been included as expenses in base rates, yet the offsetting benefits through reduced power supply costs have not been accounted for. I have adjusted the GRID model to account for the average cost and capacity for the transmission links included in the Company's response to Monsanto Data Request 2.50. This only includes non-firm transmission transactions greater than one average MW.

Q. What is the reduction in net power supply expense calculated by the GRID model if non-firm transmission benefits are included?

A. I have calculated this to be a reduction in net power supply expense of $2.5 million on a system basis. I include this adjustment in Staff's net power cost recommendation.

Q. What is the third inconsistency you have incorporated?

A. The third inconsistency surrounds the median output of the Company's Bear River hydro generation. As noted on page 10, lines 19 through 21 of Company witness Shu's testimony, Rocky Mountain Power excludes high water, or flood control years, in its calculation of median stream flow for the Bear River system.

Q. Do you agree with this calculation?

A. No, I believe this inappropriately biases the potential hydro output downward by skewing the median. While the Company may think it is unlikely this will occur in the future, there are no indications that severely dry years, while of equally low probability, have been removed as well.

Q. What is the impact of adjusting the Bear River median hydro normalization?

A. The result of adjusting the Bear River median hydro normalization results in a reduction of approximately $2.2 million on a system basis. I include this adjustment in Staff's net power cost recommendation.

Q. Do you have any other adjustments to the Company's net power cost filing?

A. No, I do not.

Q. What is the overall impact on net power cost based on your recommendations?

A. The sum of my four adjustments total a reduction in net power cost from the Company's filing of $40.9

million on a system basis. I recommend that the net power cost included in base rates for Rocky Mountain Power be $1.03 billion on a system basis. As reflected in Staff witness Vaughn's Exhibit 108, this results in an Idaho allocated net power cost of $66.6 million, or $2.6 million below the Company's filing. I should note this does not include the treatment of costs associated with the Irrigation Load Control Program as a power purchase expense, as explained in Staff witness Carlock's testimony.

Q. The Company has indicated that it will file a revised net power cost upon rebuttal. Do you believe this is appropriate?

A. While an argument can be made for having the most recent available data included in this case, I do not agree that updating the net power cost on rebuttal is appropriate. The complexity and the modeling along with the voluminous accompanying data make it impossible for any other parties to thoroughly vet the updated power cost.

Rate Design

Q. Have you reviewed the Company's rate design proposals?

A. Yes, I have.

Q. Could you please summarize the Company's position?

A. According to Company witness Griffith's testimony, Rocky Mountain Power's proposed revenue increase by class is based on the results of its class cost of service model, essentially moving all rate classes to full cost of service. Staff witness Hessing further discusses class revenue spread required in order to achieve cost of service. For large industrial customers, including special contract customers, the Company proposes equal increases to all billing determinants. For the remaining commercial customers and irrigation class, the Company proposes a slightly larger increase to demand charges than energy charges based on the results of the cost of service study. The same can be said for time-of-use residential customers (Schedule 36), with the Company maintaining the current relationships between on- and off-peak energy rates.

The biggest change proposed by the Company is a two-tiered inverted block rate design for residential Schedule 1 customers. The proposed tier break would be at 800 kWh both in the summer and non-summer seasons, with higher comparative rates in the summer. Rocky Mountain also proposes eliminating the monthly minimum charge of $10.41 and adding a monthly customer charge of $12.00.

Q. Do you believe it is reasonable to increase all billing components on an equal percentage basis for large industrial customers?

A. Yes, I do.

Q. Why do you believe that is appropriate for all of these classes?

A. It has been said in countless general rate case proceedings in the past, but it is true that cost of service is an inexact science. While it can provide guiding principles for revenue distribution between rate schedules and within rate schedules, the results cannot be looked upon as absolutes.

Also, equally spreading the revenue increases to all billing determinants still provides a significant level of fixed cost recovery while sending customers a strong price signal through relatively higher energy rates.

Q. Do you support the Company's proposal to keep the on- and off-peak differentials for Schedule 36 customers?

A. Yes, I do. Rocky Mountain Power has consistently demonstrated its time-of-use rates are both aggressive and fair.

Q. Turning to general residential rate design, what do you believe constitutes effective rate design for residential customers?

A. Effective rate design entails promoting efficient consumption of energy through proper pricing. Rocky Mountain Power, like most utilities in the Northwest, has relatively low cost generating resources to meet its average loads but relies on more expensive gas-fired resources and market purchases through much of the summer and deep winter months to meet peak loads. Flat rate design, in which kilowatt hour (kWh) rates are based on average costs and do not vary based on timing or level of consumption, do not reflect the disparity in costs to serve load during peak periods and off-peak periods.

Effective rate design also provides customers with a cost-based price signal that when consumption reaches a certain threshold, or occurs in a particular time period, the cost to provide that energy can be significantly higher than the embedded rate, and the rate charged to customers should reflect that fact. There are many ways that rates can reflect the variable cost to serve, but the two most prevalent ways are through tiered rate design and time-of-use (TOU) rates. Rocky Mountain Power has offered residential TOU rates for a number of years. This filing represents its first proposal for a tiered rate structure for residential customers.

Q. You mention that sending proper price signals is an important part of effective rate design. What other factors did you consider when approaching residential rate design?

A. I alluded to the fact that prices should reflect the cost to provide the energy. If this were carried to the extreme, an inverted rate design, which both the

Company and the Staff support, would have stark differentials between the first block or tier, and the tail block, in order to reflect the substantial difference between the embedded cost of resources and the cost of marginal resources. But the ability for customers to respond must not be ignored. When promoting tiered rates, one must not lose sight of general rate design principles: rate equity, rate stability, and opportunity for the utility to recover its approved costs.

Q. Do you believe the Company's proposal meets these design principles?

A. In many respects I do, but overall I believe there are some deficiencies in the filing. Rocky Mountain Power has proposed that its rate differential between blocks be set at 35%. I believe that this differential is substantial enough for customers to receive a strong price signal while still allowing them to control their bills. Average customers would not see a significant change in their bills under the Company's proposal, and only those smallest of users and largest of users would see significant percentage increases in their bills.

Q. Why would the smallest users receive larger increases under the Company's proposal?

A. The large percentage increase is due to removing the minimum charge currently set at $10.64, and replacing it with a $12.00 monthly customer charge. Under the current structure, those using up to a little more than 100 kWh per month paid just the minimum. Under the Company proposal, the customers would pay both the customer charge and the per-kWh rate for all energy consumed.

Q. Do you support the removal of the minimum charge in lieu of the monthly customer charge?

A. I do, though I believe the Company proposed customer charge is too high.

Q. Please elaborate.

A. While the high customer charge does reflect the third principle of cost recovery for the utility, it violates the first two principles. Moving to a high fixed monthly charge diminishes the price signal in the energy charge to conserve electricity. It also results in a nearly doubling of the monthly bill for a subset of small energy consumers, violating the rate stability concept.

Q. What do you propose as a monthly customer charge?

A. I propose a $5.00 monthly charge for Schedule 1 customers. Based on Rocky Mountain Power's Exhibit 53, this amount sufficiently covers the meter reading and billing costs for the class, which has been Staff's traditional basis for setting customer charges.

Q. How does your proposed customer charge compare to other electric utilities in Idaho?

A. If the Commission approved a $5.00 customer charge for Rocky Mountain Power, it would rank as the highest among the three investor-owned electric utilities under its jurisdiction, excluding Atlanta Power.

Q. Returning to tiered rates, is it generally regarded that this particular rate structure is an effective means to promote energy efficiency?

A. Yes. In 2005 the National Action Plan for Energy Efficiency, a public-private initiative consisting of organizations such as the Department of Energy (DOE), Environmental Protection Agency (EPA), and National Association of Regulatory Utility Commissioners (NARUC), stated that "Retail rate designs with clear and meaningful price signals, coupled with good customer education, can be powerful tools for encouraging energy efficiency." The DOE stated more recently in a 2007 report to Congress that rate design is one of 10 mechanisms for enhancing energy efficiency. The 2007 Idaho Energy Plan listed adoption of rate designs that encourage energy efficiency in its action plan to promote conservation. In each case cited, it is noted that rate design must consider the unique characteristics of the customer class.

Q. Are tiered rates common in Idaho?

A. Yes. Idaho Power currently has a three-tiered rate structure for residential and small commercial customers during the summer and non-summer periods. Avista also has a two-tiered rate structure for residential customers in Idaho. While Rocky Mountain Power currently has a flat rate structure in Idaho, it does have tiered residential rate structures in several other jurisdictions.

Q. You mentioned that characteristics unique to the customer class should be considered when designing rate structures. What "unique characteristics" of the residential class did you consider in your rate design?

A. Residential customers as a class tend to be quite homogeneous when compared to small commercial and irrigation customers, but more volatile when compared to industrial customer classes. This can be attributed to end use of electricity. Residential basic electric usage can cover lighting and home appliances, such as refrigerators and electric ovens. These tend to vary mainly with the size and occupancy of the residence. I would suggest that heating and, to a lesser degree, cooling should also be considered basic end uses, as well as a point at which residential customers begin to differ from one another. Based on the response to Staff Production Request 192, approximately 21% of Rocky Mountain Power's residential customers use electricity for space heating purposes, while others use natural gas, propane, or biofuels, such as wood-fired stoves, for heating. Similarly, many homes have central cooling systems or some means of air conditioning while many do not.

Beyond basic consumption, there is great diversity in discretionary usage such as home computers and home entertainment systems. Between discretionary usage and weather sensitive usage, the residential customers as a whole have relatively low load factors (average load divided by peak load). This impacts the cost to serve residential customers, along with the utility's ability to recover its approved costs.

Q. How does this affect residential rate design?

A. The low load factor reflects the "peakiness" of residential load profiles. Usage tends to be relatively low in spring and autumn months and higher in winter and summer months. In fact, for Rocky Mountain Power the residential class peaks in winter with a smaller peak in the summer. When designing tiered rates, it is appropriate to provide price signals that reflect the dual-season peaking nature of the class and reduce the class average use per customer.

Q. Does the Company's proposal reflect the dual-peaking nature of the residential class?

A. No, I do not believe it does. The Company proposes setting the tier block break at 800 kWh year-round, which is slightly below average annual residential consumption according to Company witness Griffith. When looking at monthly consumption, it is evident that the average is considerably higher in the winter months (949 kWh) and lower in the summer months (729 kWh), presumably due to the prevalence of electric space heating in an area of Idaho that can experience quite cold winters.

Q. What do you propose as an alternative?

A. I propose a two-tiered inverted rate structure with the summer (May through October) blocks of 0-700 kWh and 701 kWh and above. For the winter (November through April) season, I propose setting the block break at 900 kWh. I agree with the Company's proposed rate differential between the two blocks.

Q. Why do you believe this is a better design than the Company's proposal?

A. I believe that my proposal better adheres to the principles I outlined above. Reducing the monthly customer charge to a more reasonable $5.00 maintains a level of rate stability while covering the monthly billing and meter reading costs. Setting the blocks at different seasonal levels preserves the concept of cost-based price signals and rate equity. While the class may be winter peaking, it is small relative to the Company's system, which faces higher costs to serve in the summer months. The higher summer costs and lower average consumption led me to reduce the first tier block, which better reflects Company costs and sends a stronger price signal to customers. Setting the winter block higher than the Company's proposal may lessen the price signal to a degree, but maintains the block-to-average consumption relationship demonstrated in the summer design and still sends a strong price signal to customers, but acknowledges that the harsh winter conditions these customers face are not being ignored in the process.

Q. In the most recent Idaho Power general rate case, you strongly advocated for a three-tier residential rate design. Why are you not doing so in this instance?

A. There are many reasons. First, for rate design to have a significant impact on usage, customers must learn to adapt to the price signals. Idaho Power had a two-tiered residential rate in place at the time of its filing, and while it may not have been the most aggressive design, it was nevertheless the standard for residential customers during the summer months since June of 2004. It seemed a natural progression to go from a two-tiered structure to a three-tiered structure in that case.

Rocky Mountain Power customers in Idaho have not faced anything other than seasonal flat rates since the 1970's, at least. The movement to a tiered rate structure will have immediate positive bill impacts on some customers and negative impacts on others. I do not want to overestimate the rate at which customers will be able to adjust their consumption patterns to the new rate design, thus jumping to a three-tiered rate seems premature at this point for Rocky Mountain Power.

Q. What other reasons lead you to advocate a two-tiered rate over a three-tiered rate?

A. I do not believe that the rate design can have as material an effect on Rocky Mountain's long-term resource acquisition path as it could for Idaho Power. Residential customers account for a significant portion of Idaho Power's system demand and peak. The same cannot be said for residential customers in Rocky Mountain Power's Idaho service territory. The fact that this rate class contributes such a small percentage to system peak and load reduces the long-term benefits that may manifest through tiered rates. That said, it does not diminish the argument that in the short run, rates should reasonably reflect cost to serve and provide price signals to customers to promote conservation and efficient energy consumption.

As a final point, Rocky Mountain Power is much less reliant on expensive peaking resources to meet its demand and energy needs when compared to Idaho Power. In other words, its resource mix leans more heavily on baseload and intermediate resources (as well as market purchases) than Idaho Power, thus muting the immediate need to institute a tier for the highest energy consumers.

Q. Have you incorporated the results of Staff witness Hessing's cost of service and revenue spread into your rate design?

A. Yes, I have. As described by Mr. Hessing, all residential customers would receive an equal percentage increase in revenue requirement. I propose increasing the Schedule 36 monthly customer charge to $14.00, and spreading the remaining revenue deficiency equally to the energy rates. Under Staff's proposal, Schedule 1 customers would have a $5.00 monthly charge and the remaining revenue shortfall spread would be distributed as proposed by the Company, which means some customers would see a bill increase while others would see a decrease. Of the remaining classes, I have spread the revenue deficiency equally to all billing components.

Q. Why does Staff propose an equal percentage increase to Schedule 1 and Schedule 36 customers?

A. Staff does not believe the Company has provided adequate justification through cost of service to support its proposed increase in residential Schedule 36 residential customers.

Q. Please elaborate.

A. The Company's filing demonstrates a belief that

Schedule 36 will shrink compared to Schedule 1. Rocky Mountain supported this notion due to recent trends in the customer groups. But based on the Company response to Staff Production Request 288, I do not believe the trends are necessarily accurate. The Company continued the downward trend in Schedule 36 customer numbers from 2009, but failed to incorporate the fact that the previous three year did not exhibit such a trend. Company response to Staff Production Request 291 confirmed that estimates used to forecast Schedule 36 energy were significantly understated in relation to Schedule 1 consumption. Until the Company's load research data becomes more reliable, I propose that residential customers remained aggregated, as it is for calculating jurisdictional load factors. The end result is a uniform percentage increase for Schedule 1 and Schedule 36.

Q. Have you prepared an exhibit demonstrating the results of Staff's rate spread proposal?

A. Yes, I have included Staff Exhibit No. 109, which shows the rate components currently in place, as proposed by the Company, and Staff's proposal for each class. It should be noted that Staff's energy rate for Schedule 1 is higher than that proposed by the Company even with Staff's lower revenue requirement. That is due to the significantly lower proposed customer charge. The revenue generated by the class is equal to that submitted by Mr. Hessing.

Q. Have you prepared an exhibit demonstrating the impact of Staff's proposal on Schedule 1 customer bills?

A. Yes. I have updated a version of Company Exhibit 54, Schedule 1 with Staff's revenue requirement and rate design proposals. It is included as Staff Exhibit No. 110.

Q. Have you prepared an exhibit demonstrating the impact of Staff's proposal on Schedule 36 customer bills?

A. Yes. I have updated a version of Company Exhibit 54, Schedule 36 with Staff's revenue requirement and rate design proposals. It is included as Staff Exhibit No. 111.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

CASE NO. PAC-E-10-07
IPUC STAFF
COMPARISON OF PRESENT RATE STRUCTURE
TO COMPANY AND STAFF PROPOSALS
BY RATE SCHEDULES IN IDAHO

Line No.	Description	Sch.	Billing Component		Present	Company Proposed	Staff Proposed
	(1)	(2)	(3)		(4)	(5)	(6)
	Residential Sales						
1	Residential Service	1	Minimum Charge		$10.64	none	none
2			Customer Charge		none	$12.00/month	$5.00/month
3			May-Oct				
4			First Block kWh Rate	(¢)	10.4093	0-800: 8.9526	0-700: 9.3836
5			Second Block kWh Rate	(¢)	10.4093	> 800: 12.0860	>700: 12.6679
6			Nov-Apr				
7			First Block kWh Rate	(¢)	8.015	0-800: 6.5519	0-900: 7.0668
8			Second Block kWh Rate	(¢)	8.015	> 800: 8.8451	>900: 9.5402
9	Residential Optional TOD	36	Customer Charge		$13.63	$16.00	$14.00
10			May-Oct On-Peak	(¢)	11.3497	13.094	11.9246
11			May-Oct Off-Peak	(¢)	3.873	4.4682	4.0692
12			Nov-Apr On-Peak	(¢)	9.695	11.185	10.1861
13			Nov-Apr Off-Peak	(¢)	3.5447	4.0894	3.7243
14	**Commercial & Industrial**						
15	General Service - Large Power (a)	6, 6A	Cust. Charge (Secondary)		$30.97	$36.00	$33.00
16			Cust. Charge (Primary)		$97.91	$108.00	$99.00
17			Demand (May-Oct) (KW)		$11.34	$13.30	$12.24
18			Demand (Nov-Apr) (KW)		$9.33	$10.95	$10.07
19			kWh Rate	(¢)	3.138	3.5266	3.3863
20	General Service - High Voltage (a)	9	Voltage Discount	($)	(0.53)	(0.62)	(0.57)
21			Customer Charge		$301.10	$345.00	$325.00
22			Demand (May-Oct) (KW)		$7.88	$9.57	$8.50
23			Demand (Nov-Apr) (KW)		$5.96	$7.24	$6.43
24			kWh Rate	(¢)	3.2519	3.6244	3.5093

(a) Rocky Mountain Power proposes a greater increase in demand components than energy components. Staff proposes uniform increase to all components.

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Line No.	Description (1)	Sch. (2)	Billing Component (3)		Present (4)	Company Proposed (5)	Staff Proposed (6)
25	Irrigation (a)	10	In-Season (June 1-Sept 15)				
26			Small Cust. Charge		$11.74	$13.00	$12.00
27			Large Cust. Charge		$34.14	$37.00	$35.00
28			Demand (KW)		$4.55	$5.53	$4.69
29			First 25,000 kWh	(¢)	7.1315	7.6106	7.3495
30			Next 225,000 kWh	(¢)	5.275	5.6294	5.4362
31			All add'l kWh	(¢)	3.9095	4.1699	4.0216
32			Post Season (Sept 16- May 31)				
33			Customer Charge		$18.08	$20.00	$19.00
34			kWh Rate	(¢)	6.0315	6.6102	6.2158
35	Comm. & Ind. Space Heating	19	Customer Charge		$20.10	$23.00	$21.00
36			kWh Rate (May-Oct)	(¢)	7.8457	8.7759	8.2838
37			kWh Rate (Nov-Apr)	(¢)	5.8133	6.5025	6.1379
38	General Service	23	Customer Charge Secondary		$13.72	$15.00	$14.00
39			Customer Charge Primary		$41.16	$46.00	$43.00
40			kWh Rate (May-Oct)	(¢)	7.6737	8.52	8.0627
41			kWh Rate (Nov-Apr)	(¢)	6.6985	7.4373	7.038
42			Voltage Discount	(¢)	(0.37)	(0.41)	(0.39)
43	General Service Optional TOD	35	Customer Charge Secondary		$54.75	$63.00	$59.00
44			On-Peak Demand (KW)		$13.48	$15.48	$14.54
45			kWh Rate	(¢)	4.0167	4.6137	4.334
46			Voltage Discount	($)	(0.69)	(0.79)	(0.74)

(a) Rocky Mountain Power proposes a greater increase in demand components than energy components. Staff proposes uniform increase to all components.

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Line No.	Description	Sch.	Billing Component		Present	Company Proposed	Staff Proposed
	(1)	(2)	(3)		(4)	(5)	(6)
47	Special Contract 1 (b)	400	Customer Charge		$1,227.00	$1,468.00	$1,386
48			Demand (KW)		$12.27	$14.68	$13.86
49			kWh Rate	(¢)	2.381	2.849	2.689
50			Excess KVar		$0.75	$0.90	$0.85
51	Special Contract 2	401	Customer Charge		$341.33	$396.00	$374.00
52			May-October				
53			HLH kWh Rate		2.808	3.255	3.077
54			LLH kWh Rate		$2.11	2.442	2.308
55			Demand (KW)		$13.60	$15.77	$14.90
56			November-April				
57			HLH kWh Rate		2.336	2.706	2.56
58			LLH kWh Rate		2.106	2.442	2.308
59			Demand (KW)		$10.97	$12.72	$12.02
60	**Public Street Lighting**	7, 11, 12	All Components		N/A	No Change	No Change

(b) Does not contain rate adjustments due to interruptibility credit.

Case No. PAC-E-10-07
IPUC Staff
Monthly Billing Comparison
Schedule 1
Residential Service

	Monthly Billing[1]				Change				Annual	
	Present		Proposed		$		%		Average Change	
kWh	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	$	%
0	$11.04	$11.04	$5.19	$5.19	($5.85)	($5.85)	-53.0%	-53.0%	($5.85)	-53.0%
100	$11.04	$11.04	$15.02	$12.62	$3.99	$1.58	36.1%	14.3%	$2.79	25.2%
200	$21.80	$16.83	$24.86	$20.05	$3.06	$3.22	14.0%	19.1%	$3.14	16.2%
300	$32.70	$25.25	$34.70	$27.49	$1.99	$2.24	6.1%	8.9%	$2.12	7.3%
400	$43.60	$33.67	$44.53	$34.92	$0.93	$1.25	2.1%	3.7%	$1.09	2.8%
500	$54.50	$42.08	$54.37	$42.35	($0.13)	$0.27	-0.2%	0.6%	$0.07	0.1%
600	$65.40	$50.50	$64.20	$49.79	($1.20)	($0.71)	-1.8%	-1.4%	($0.96)	-1.6%
700	$76.30	$58.92	$74.04	$57.22	($2.26)	($1.70)	-3.0%	-2.9%	($1.98)	-2.9%
729 s	$79.46		$76.89		($2.57)		-3.2%		($2.57)	-3.2%
800	$87.20	$67.34	$83.88	$64.65	($3.32)	($2.68)	-3.8%	-4.0%	($3.00)	-3.9%
839 a	$91.45	$70.62	$89.04	$68.55	($2.41)	($2.06)	-2.6%	-2.9%	($2.24)	-2.8%
900	$98.10	$75.75	$97.12	$74.65	($0.98)	($1.10)	-1.0%	-1.5%	($1.04)	-1.2%
949 w		$79.88		$79.55		($0.32)		-0.4%	($0.32)	-0.4%
1,000	$109.00	$84.17	$110.36	$84.65	$1.36	$0.48	1.2%	0.6%	$0.92	1.0%
1,100	$119.90	$92.59	$123.61	$94.65	$3.70	$2.06	3.1%	2.2%	$2.88	2.7%
1,200	$130.80	$101.00	$136.85	$104.65	$6.05	$3.65	4.6%	3.6%	$4.85	4.2%
1,400	$152.60	$117.84	$163.33	$124.65	$10.73	$6.81	7.0%	5.8%	$8.77	6.5%
1,600	$174.40	$134.67	$189.82	$144.64	$15.42	$9.97	8.8%	7.4%	$12.69	8.2%
1,800	$196.20	$151.50	$216.31	$164.64	$20.10	$13.14	10.2%	8.7%	$16.62	9.6%
2,000	$218.00	$168.34	$242.79	$184.64	$24.79	$16.30	11.4%	9.7%	$20.54	10.6%
2,500	$272.51	$210.42	$309.01	$234.63	$36.50	$24.21	13.4%	11.5%	$30.36	12.6%
3,000	$327.01	$252.51	$375.22	$284.63	$48.21	$32.12	14.7%	12.7%	$40.17	13.9%
5,000	$545.01	$420.84	$640.08	$484.60	$95.07	$63.76	17.4%	15.2%	$79.41	16.4%

[1] Includes current Schedule 34-BPA Credit which equals zero, Energy Cost Adjustment and Customer Efficiency Services Rate Adjustment.

s, w, a: Monthly average usage for summer, winter and annual respectively.

Exhibit No. 110
Case No. PAC-E-10-07
B. Lanspery, Staff
10/14/10

Case No. PAC-E-10-07
IPUC Staff
Monthly Billing Comparison
Schedule 36
Residential Service-Optional Time of Day

	Monthly Billing[1]				Change			
	Present		Proposed		$		%	
kWh	Summer[2]	Winter[3]	Summer[2]	Winter[3]	Summer	Winter	Summer	Winter
0	$14.14	$14.14	$14.52	$14.52	$0.38	$0.38	2.7%	2.7%
50	$17.90	$17.33	$18.48	$17.88	$0.57	$0.54	3.2%	3.1%
100	$21.67	$20.53	$22.43	$21.24	$0.76	$0.70	3.5%	3.4%
150	$25.44	$23.73	$26.38	$24.59	$0.95	$0.86	3.7%	3.6%
200	$29.20	$26.93	$30.34	$27.95	$1.14	$1.02	3.9%	3.8%
300	$36.74	$33.32	$38.25	$34.66	$1.51	$1.34	4.1%	4.0%
400	$44.27	$39.72	$46.16	$41.38	$1.89	$1.66	4.3%	4.2%
500	$51.80	$46.12	$54.07	$48.09	$2.27	$1.98	4.4%	4.3%
600	$59.33	$52.51	$61.98	$54.81	$2.64	$2.30	4.5%	4.4%
700	$66.87	$58.91	$69.89	$61.52	$3.02	$2.61	4.5%	4.4%
800	$74.40	$65.30	$77.79	$68.24	$3.39	$2.93	4.6%	4.5%
900	$81.93	$71.70	$85.70	$74.95	$3.77	$3.25	4.6%	4.5%
1,000	$89.47	$78.09	$93.61	$81.67	$4.15	$3.57	4.6%	4.6%
1,100	$97.00	$84.49	$101.52	$88.38	$4.52	$3.89	4.7%	4.6%
1,200	$104.53	$90.89	$109.43	$95.09	$4.90	$4.21	4.7%	4.6%
1,400	$119.60	$103.68	$125.25	$108.52	$5.65	$4.85	4.7%	4.7%
1,600	$134.66	$116.47	$141.07	$121.95	$6.40	$5.48	4.8%	4.7%
1,800	$149.73	$129.26	$156.89	$135.38	$7.16	$6.12	4.8%	4.7%
2,000	$164.80	$142.05	$172.71	$148.81	$7.91	$6.76	4.8%	4.8%
2,500	$202.46	$174.03	$212.25	$182.38	$9.79	$8.35	4.8%	4.8%
3,000	$240.12	$206.01	$251.80	$215.95	$11.67	$9.95	4.9%	4.8%

[1] Includes current Schedule 34-BPA Credit which equals zero, Energy Cost Adjustment and Customer Efficiency Services Rate Adjustment.
[2] Bills are based on 44%-56% on-peak to off-peak ratio in the summer
[3] Bills are based on 41%-59% on-peak to off-peak ratio in the winter

Exhibit No. 111
Case No. PAC-E-10-07
B. Lanspery, Staff
10/14/10

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14TH DAY OF OCTOBER 2010, SERVED THE FOREGOING **DIRECT TESTIMONY OF BRYAN LANSPERY**, IN CASE NO. PAC-E-10-07, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

TED WESTON
ID REGULATORY AFFAIRS MANAGER
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2300
SALT LAKE CITY UT 84111
(FED EX)
E-MAIL: ted.weston@pacificorp.com

PAUL J HICKEY
HICKEY & EVANS LLP
1800 CAREY AVE., SUITE 700
PO BOX 467
CHEYENNE WY 82003
(FED EX)
E-MAIL: phickey@hickeyevans.com

E-MAIL: ONLY
MARK C MOENCH
DANIEL E SOLANDER
ROCKY MOUNTAIN POWER
E-MAIL: mark.moench@pacificorp.com
daniel.solander@pacificorp.com

E-MAIL: ONLY
KATIE IVERSON
BRUBAKER & ASSOCIATES
E-MAIL: kiverson@consultbai.com

RANDALL C BUDGE
RACINE OLSON NYE ET AL
PO BOX 1391
POCATELLO ID 83204-1391
(FED EX)
E-MAIL: rcb@racinelaw.net

ERIC L OLSEN
RACINE OLSON NYE ET AL
PO BOX 1391
POCATELLO ID 83204-1391
(FED EX)
E-MAIL: elo@racinelaw.net

E-MAIL: ONLY
JAMES R SMITH
MONSANTO COMPANY
E-MAIL: jim.r.smith@monsanto.com

ANTHONY YANKEL
29814 LAKE ROAD
BAY VILLAGE OH 44140
(FED EX)
E-MAIL: tony@yankel.net

TIM BULLER
JASON HARRIS
AGRIUM INC
3010 CONDA RD
SODA SPRINGS ID 83276
(FED EX)
E-MAIL: tbuller@agrium.com
jaharris@agrium.com

E-MAIL: ONLY
DR. DON READING
E-MAIL: dreading@mindspring.com

RONALD L WILLIAMS
WILLIAMS BRADBURY, P.C.
1015 W HAYS STREET
BOISE ID 83702
(HAND CARRIED)
E-MAIL: ron@williamsbradbury.com

BENJAMIN J OTTO
IDAHO CONSERVATION LEAGUE
710 N 6TH STREET
PO BOX 844
BOISE ID 83702
(HAND CARRIED)
E-MAIL: botto@idahoconservation.org

MELINDA J DAVISON
DAVISON VAN CLEVE, P.C.
333 SW TAYLOR, SUITE 400
PORTLAND, OR 97204
(FED EX)
E-MAIL: mjd@dvclaw.com

BRAD M PURDY
ATTORNEY AT LAW
2019 N 17TH STREET
BOISE ID 83702
(HAND CARRIED)
E-MAIL: bmpurdy@hotmail.com

Jo Nelson
SECRETARY