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Attorneys for PacifiCorp Idaho Industrial Customers

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $27.7 MILLION OR APPROXIMATELY 13.7 PERCENT	)	**CASE NO. PAC-E-10-07**

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF DONALD SCHOENBECK, RANDALL J. FALKENBERG, AND GREG R. MEYER

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October 14, 2010

Via Email and Federal Express

Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, ID 83720-0074

Re: In the matter of the Application of PacifiCorp d/b/a Rocky Mountain Power for Approval of Changes to its Electric Service Schedules
Case No. PAC-E-10-07

Dear Ms. Jewell:

Enclosed please find an original and nine (9) copies of the Direct Confidential Testimony of Greg Meyer and Randall Falkenberg, the original and nine (9) copies of the Direct Redacted Testimony of Greg Meyer and Randall Falkenberg, and the original and nine (9) copies of the Direct Testimony of Donald Schoenbeck.

Thank you for your assistance.

Sincerely yours,

Sarah A. Kohler

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the Direct Testimony of Greg Meyer, Randall Falkenberg, and Donald Schoenbeck on behalf of Industrial Customers of Northwest Utilities upon all parties of record in this proceeding by mailing a copy thereof in a sealed, first-class postage prepaid envelope to each individual's last-known address, as listed below. Confidential versions were sent only to individuals who signed the protective order.

DATED this 14th day of October, 2010.

Davison Van Cleve, P.C.

Sarah A. Kohler

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATIONOF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $27.7 MILLION OR APPROXIMATELY 13.7 PERCENT	)	**CASE NO. PAC-E-10-07** **Direct Testimony of Donald W. Schoenbeck**

DIRECT TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

October 14, 2010

I. INTRODUCTION AND SUMMARY

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A.** My name is Donald W. Schoenbeck. I am a member of Regulatory &
3 Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm.
4 My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

5 **Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.**

6 **A.** I've been involved in the electric and gas utility industries for over 35 years. For
7 the majority of this time, I have provided consulting services for large industrial
8 customers addressing regulatory and contractual matters. A further description of
9 my educational background and work experience can be is attached as Exhibit
10 601 in this proceeding.

11 **Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

12 **A.** I am testifying on behalf of the PacifiCorp Idaho Industrial Customers ("PIIC").
13 PIIC is a coalition of Idaho industrial companies served by Rocky Mountain
14 Power ("RMP" or the "Company").

15 **Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?**

16 **A.** I will address the Company's hourly load data, certain aspects of the Company's
17 cost-of-service study presented in Exhibit No. 49, the Company's proposed rate
18 spread presented in Exhibit No. 50 and Schedule 6, 6A and 9 rate design. This
19 testimony will not address revenue requirement issues. PIIC is submitting
20 separate testimony regarding revenue requirement matters.

1 **Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND**
2 **RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.**

3 **A.** The Company's jurisdictional separation study uses hourly load data from 2010 to
4 assign system costs between the various state jurisdictions with certain
5 adjustments. However, the Company's cost-of-service study uses hourly load
6 data from 2009 for most classes and an average of five historical years for the
7 irrigation class (Schedule 10) and one of the contract customers for assigning
8 generation and transmission demand-related costs. In future proceedings, PIIC
9 recommends the same load research data be used in both studies to more
10 accurately determine cost responsibility. The demand allocation factors used in
11 the Company's cost of service study should be modified to more accurately assign
12 demand-related costs. I recommend the class demand allocation factor be based
13 on the comparable jurisdictional peak hour with a more up to date irrigation class
14 demand. The Company's twelve monthly coincident peak factor ("12 CP") for
15 assigning generation and transmission-related demand costs should be replaced
16 with a winter/summer peak factor ("W/S CP") using the peak load months of July
17 and December. The weighted twelve monthly peak factor used by the Company
18 for distribution-related demand costs should be replaced with the class maximum
19 peak demands ("1 NCP") to more accurately assign distribution cost
20 responsibility.

21 The Company's rate spread recommendation is based on the results
22 indicated by its cost study. PIIC supports a cost-based rate spread approach, but it

should be done using the results of the PIIC cost-of-service study.

The Company's Schedule 6, 6A and 9 rate design applies a slightly greater increase to the demand charges as compared to the energy charges. PIIC supports this cost-based rate design for these rate schedules.

II. HOURLY LOAD DATA

Q. PLEASE EXPLAIN THE RELEVANCE OF LOAD RESEARCH DATA.

A. Load research data is the necessary foundation of any cost-of-service study. Most of the meters installed for billing purposes do not have the capability to record customer usage by time period (for example, at five minute intervals). Typical meters for residential customers and small commercial customers simply record accumulated energy usage (kilowatt-hours, or "kWhs"). The next most prevalent meters—installed for customers on a tariff with demand charges—record the accumulated kWhs and the peak hourly value for the billing period. Usually, only the largest customers—such as those on Schedule 9—have "time-of-use" meters installed. These meters record energy usage at very small time intervals—typically every five minutes. Consequently, it is necessary to undertake a load research program and install time-of-use meters—generally through a sampling selection process—to ascertain class demand levels and class contributions to system or local peaks for almost all classes of customers. Absent this critical information, "guestimates" must be made to derive the demand allocation factors used to assign class cost responsibility within a cost-of-service study.

1 **Q. DOES THE COMPANY HAVE CURRENT LOAD RESEARCH**
2 **INFORMATION FOR ALL CUSTOMER CLASSES?**

3 **A.** Yes. The Company's response to the Idaho Irrigation Pumpers Association, Inc.
4 ("IIPA") Data Request 2D (attached as Exhibit 603) indicates the time period over
5 which the load research data was collected. Except for Schedule 19, the data
6 response indicates very recent time periods. The Company's response to IIPA
7 Data Request 8 (attached as Exhibit 604) includes an EXCEL spreadsheet that
8 contains the 2009 test period hourly loads for each class. The hourly load
9 research data from 2009 was adjusted upward or downward to achieve the
10 monthly energy sales level for each class. The Company provided this data as
11 support for the class cost-of-service study demand allocation factors.

12 **Q. DID THE COMPANY USE THIS SAME TYPE OF HOURLY CLASS**
13 **LOAD DATA IN ITS JURISDICTIONAL SEPARATION STUDY TO**
14 **DERIVE THE ALLOCATION OF SYSTEM COSTS TO IDAHO?**

15 **A.** No. As noted in the written response to IIPA 8, the Idaho jurisdictional loads
16 were not derived from class hourly load data. The response states that "different
17 data sources" are used and that the class load data does not "flow through to the
18 state jurisdiction load."

19 **Q. HAVE YOU ANALYZED AND COMPARED THE JURISDICTIONAL**
20 **PEAKS AND THE CLASS LOAD PEAKS?**

21 **A.** Yes. The following table presents the monthly Idaho jurisdictional megawatt
22 ("MW") peak values from RMP's Exhibit 2, page 10.13, with the class peak
23 demands set forth in Exhibit 49.

Hourly Load Comparison Coincident System Peaks – MWs				
Month	**Jurisdictional Data**	**Adjusted Jurisdictional Data**	**Cost Study Data**	**Difference Cost Study - Adj Juris**
January	406	406	466	60
February	416	416	434	18
March	399	399	396	-3
April	415	415	387	-28
May	503	503	442	-61
June	613	429	633	204
July	664	475	496	21
August	538	356	534	178
September	447	447	388	-59
October	406	406	372	-34
November	443	443	414	-29
December	467	467	404	-63

The values in the column labeled "Jurisdictional Data" are the projected peaks prior to any adjustments for any load curtailment or dispatch program. The column labeled "Adjusted Jurisdictional Data" are the values that are used to allocate and assign system related costs to Idaho. In this column, the months of June, July and August contain lower values (about 185 MWs) reflecting the expected curtailment attributable to the irrigation load control programs. The column labeled "Cost Study Data" shows the aggregate system peak used in the cost study. For this column, it should be noted that the peak demand for the irrigation class is derived from five years of historical data affecting the demands for the months of June through September. (The Company used a five year average of historical data for one contract customer as well). The last column in the above table shows the difference between the adjusted jurisdictional load and

class demand total. A cursory review of this column raises concerns over the level of the irrigation peak demand in the cost study during the irrigation season but there are differences in all other months that cannot be explained by simply the one year difference represented by the data (2009 versus 2010).

Q. ARE THE PEAK DEMANDS IN THE ABOVE TABLE FOR THE SAME DAY AND HOUR OF EACH MONTH?

A. No. The following table shows the day and hour of the peak demand used in the jurisdictional separation study and the class cost of service study.

Comparison of Peak Hours Coincident System Peaks		
Month	**Jurisdictional Peaks**	**Company Cost Study**
January	25th, 19:00	27th, 9:00
February	4th, 8:00	10th, 20:00
March	30th, 8:00	11th, 9:00
April	1st, 8:00	1st, 10:00
May	18th, 15:00	29th, 17:00
June	24th, 15:00	29th, 18:00
July	19th, 16:00	27th, 18:00
August	26th, 15:00	3rd, 18:00
September	9th, 15:00	2nd, 17:00
October	4th, 19:00	28th, 10:00
November	24th, 18:00	30th, 19:00
December	15th, 18:00	9th, 9:00

As shown by the table, there is only one single month—April—where the two studies use the same peak day. There is no month when the same hour is used. Given the readily available load research data the Company has, there should be a direct linkage between the data used in the jurisdictional and class studies. By doing so, the monthly peak hours and loads would be the same in the two studies.

Q. HAVE YOU COMPARED THE CLASS LOAD DATA BETWEEN THE JURISDICTIONAL PEAK HOUR AND THE COMPARABLE CLASS PEAK HOURS

A. Yes. The following table shows the class peaks for the same hour and same day of the week as had been used in the jurisdictional study. In other words, as the January system peak was a Monday, the class study value shown in the following table is for Monday, January 26, 2009 at 19:00 hours.

Hourly Load Comparison - Jurisdictional Hours Coincident System Peaks			
Month	**Class Load Data**	**Company Cost Study**	**Difference Cost Study - Class Load Data**
January	460	466	6
February	440	434	-6
March	365	396	31
April	428	387	-41
May	453	442	-11
June	601	633	32
July	567	496	-71
August	534	534	0
September	422	388	-34
October	373	372	-1
November	395	414	19
December	387	404	17

The above table shows a wide variation between the two sources across all twelve months. While there are some months where the values are quite close (January, February, May, August and October), there are also several months where the difference are quite large (March, April, July and September). These differences would not exist if the Company used the same load research data for both the

jurisdictional and class studies. PIIC recommends the Commission require this of the Company in future proceedings.

III. COST OF SERVICE – PEAK DEMAND SELECTION

Q. HAVE YOU ANALYZED THE COST-OF-SERVICE STUDY PRESENTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes. I analyzed the Company's cost-of-service study submitted as Exhibit 49, reviewed the associated workpapers, reviewed the Company's responses to data requests of other parties addressing cost-of-service matters and sought additional information through PIIC data requests.

Q. DO YOU AGREE WITH THE MANNER IN WHICH THE STUDY WAS DONE?

A. No. I disagree with the method employed by the Company to allocate demand-related generation, transmission and distribution costs.

Q. HOW HAS THE COMPANY CALCULATED THE PEAK DEMANDS USED IN ITS COST-OF-SERVICE STUDY?

A. The Company's study uses two main demand (or peak) allocation factors: class coincident demands for generation and transmission costs and a weighted monthly class coincident demand for major distribution costs (substations, pole, cable and conductor). For each of these demands, the Company uses the class values from all 12 months of the year. For the generation and transmission demand allocation factor, it is simply the sum of all twelve monthly coincident peak values ("12 CP"). For the main distribution demand allocation factor, the Company starts with the same twelve monthly coincident class values as used for the generation

and transmission allocation factor. However, the Company applies a monthly weighting factor to the class peaks based upon the number of distribution substation peaks that have occurred in each month for the last five years. The following table shows the derivation of these monthly weighting factors.

Idaho Distribution Substation Peak Month							
Month	2005	2006	2007	2008	2009	5 Yr Avg	Weight
January	6	1	9	11	2	5.8	8.01%
February	4	0	3	6	1	2.8	3.87%
March	0	2	0	0	2	0.8	1.10%
April	2	1	1	1	1	1.2	1.66%
May	0	4	4	2	5	3	4.14%
June	17	13	20	8	5	12.6	17.40%
July	32	28	14	32	19	25	34.53%
August	4	12	13	8	22	11.8	16.30%
September	1	2	1	1	2	1.4	1.93%
October	2	0	1	0	0	0.6	0.83%
November	2	3	2	1	1	1.8	2.49%
December	2	6	5	3	12	5.6	7.73%
Total	72	72	73	73	72	72.4	100.00%

As shown by the final weighting factors, the Company's approach tends to emphasize the peak demands that occur during the three summer months (with factors ranging from 16.3% to 34.5%) as compared to all other months.

Q. WHY DO YOU DISAGREE WITH THE USE OF ALL TWELVE MONTHLY PEAKS FOR THE GENERATION AND TRANSMISSION DEMAND ALLOCATION FACTOR?

A. Using a value based upon all twelve months is inappropriate as it dramatically understates the demand level of certain classes. Giving each and every month equal weighting ignores the fundamental driver of new generation, transmission

1 or distribution investment. The need for these facilities is determined based on
2 the peak demands placed on such facilities. Including other irrelevant demands in
3 the derivation of the class value simply causes a shift in cost responsibility to
4 other classes in the cost study. This latter point can be appreciated by reviewing
5 the following table containing the adjusted PacifiCorp[1/] system monthly peak data
6 from RMP's Exhibit 2, page 10.2.

Monthly Peak Load Comparison Coincident System Peaks			
Month	Adjusted Jurisdictional Data	Percent of Peak Month	MWs Below Peak Month
January	8,514	93%	664
February	8,221	90%	957
March	7,661	83%	1,516
April	7,257	79%	1,921
May	7,848	86%	1,330
June	8,407	92%	771
July	9,178	100%	0
August	8,975	98%	202
September	8,356	91%	822
October	7,336	80%	1,842
November	8,322	91%	856
December	8,722	95%	455

7 Most of the months have peak demands substantially below the summer peak
8 value that occurs in July. However, the December value is relatively close
9 (within 5%) thereby identifying PacifiCorp as having a dual peak with both winter

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1/ When I reference PacifiCorp in this testimony, I am referring to PacifiCorp's entire six state system and not just RMP.

and summer months being important. For most of the remaining months, the peak load level is significantly below the peak demand level. For example, the four months of March, April, May and October are over 1,000 MWs less than the system peak value. As generation and transmission demand-related costs represent a substantial amount of the Company's proposed revenue requirement, use of the Company's 12 CP system demand allocation factor is wrong. The Company's generation and transmission demand related costs should be allocated using the July and December jurisdictional peak hours, taking into account an appropriate adjustment for the irrigation class in July to reflect the load control programs.

Q. WHY DOES THE IRRIGATION CLASS LOAD NEED TO BE ADJUSTED?

A. As previously noted, the irrigation class demand is based on the average load level for the past five years. This is inappropriate as the Company's load control programs for the irrigation class have grown substantially in recent years. The following table shows the avoided MWs for just the irrigation dispatch program compiled from the Company's Schedule 72 & 72A Idaho Irrigation Load Control Program Reports. This shows a substantial growth in the program from just 2007 to 2009 of over 160 MW. Further, the Company's response to IIPA Data Request 23 indicates an expected 2010 avoided load of 282 MWs in July under the Idaho load control programs. Basing the 2009 irrigation load level on years prior to 2009 will overstate the demand contribution for this class due to the substantial

in program participation.

Dispatch Program Avoided Demand - MWs		
Year	Highest Mean Event	Highest Hour
2007	76	76
2008	203	210
2009	237	242
Average:	172	176
2009 - Avg	65	

Q. HOW SHOULD THE IRRIGATION CLASS LOAD BE ADJUSTED?

A. There are at least two ways in which a reasonable adjustment could be done. Using the Company's historical class load data, the Company could re-construct the hourly class loads assuming no curtailments had occurred in 2009. Then the current expected program curtailment amount could be deducted from the summer irrigation months to arrive at the value to use for cost allocation purposes. As an example to illustrate this approach, assume the "un-curtailed" irrigation demand for the July peak hour is 350 MWs and the expected net avoided MWs given current customer participation levels is 250 MWs. The adjusted July peak for this class would be 100 MWs (350 MWs – 250 MWs = 100MWs). A second method is to rely in part on the jurisdictional hourly load data using the assumed level of net curtailment from the jurisdictional study applied to the class load data. To illustrate this approach, the unadjusted Idaho coincident peak for July is 664 MWs while the adjusted peak is 475 MWs. For the comparable hour, the class load data has an Idaho peak of 567 MWs, a value 92 MWs above the jurisdictional value.

This amount can be deducted from the irrigation class load for this hour to approximate the adjusted irrigation class demand for July. Given that the second method can be readily implemented, I recommend this adjustment be incorporated into the class cost study.

Q. PLEASE PROVIDE A COMPARISON OF THE COMPANY'S 12 CP DEMAND ALLOCATION FACTOR WITH YOUR RECOMMENDATIONS FOR ALLOCATING GENERATION AND TRANSMISSION DEMAND-RELATED COSTS.

A. The following table compares the MW values for the Company 12 CP allocation factor with the results of incorporating my recommendations for using the comparable jurisdictional peak hour, using only the class loads from the peak months of July and December and adjusting the July irrigation class load to reflect the current program participation levels.

System Allocation Factor Comparison – MWs			
	Company 12 CP	PIIC W/S CP	Delta
Residential	109	105	-4
Small Power (23)	26	26	0
Large Power (6/3	52	49	-3
High Voltage	14	13	-2
Irrigation (10)	72	67	-5
Lighting	0	0	0
Space Heating	1	1	0
Contract 1	161	156	-5
Contract 2	11	7	-4
Total	**447**	**425**	**-22**

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S APPROACH IN DETERMINING THE DISTRIBUTION DEMAND ALLOCATION FACTOR FOR SUBSTATIONS, POLES AND WIRE?

A. The Company's use of the 12 CP coincident demands as a starting point in its

derivation of the distribution demand allocation factor ignores the localized diversity that exists on the Company's distribution system. The 72 distribution substations have a capacity of over 1,100 MWs in order to provide reliable localized service. For 2009, these substations had an accumulated peak load of 628 MWs. Yet, the highest coincident peak for all twelve months used in the Company's allocation factor is just 483 MWs and the average of the 12 monthly distribution coincident peaks is less than 300 MWs.

Application of the Company's monthly weighting factors tends to lessen the impact of using all 12 monthly values but in actuality, this is an unnecessary step. Absent having the most accurate metric (class loads at each substation peak), a reasonable—and most often used—alternative is class non-coincident demand levels as acknowledged by the NARUC Electric Utility Cost Allocation Manual ("1 NCP"). PIIC recommends this method be used to ascertain distribution demand-related cost responsibility. The following tables compare: 1) the Company's weighted 12CP demand approach; 2) the maximum coincident demand for each class; and 3) the class maximum non-coincident peak demand ("1 NCP") I derived from the hourly load research data.

Distribution Peak Demands (MWs)			
Class (Schedules)	Company Weighting Method	Maximum Coincident Peak	Maximum Class Hourly Peak
Residential (1/36)	113	194	208
Small Power (23)	25	35	38
Large Power (6/35)	53	64	68
Irrigation (10)	199	314	320
Total:	**390**	**606**	**633**

Distribution Allocation Factor			
Class (Schedules)	Company Weighting Method	Maximum Coincident Peak	Maximum Class Hourly Peak
Residential (1/36)	28.90%	32.00%	32.80%
Small Power (23)	6.40%	5.70%	6.10%
Large Power (6/35)	13.60%	10.60%	10.70%
Irrigation (10)	51.10%	51.70%	50.50%
Total:	**100.00%**	**100.00%**	**100.00%**

It is apparent from the table that the Company's method has understated the costs assigned to Schedules 1 and 36 while overstating the distribution demand costs assigned to all other major rate schedules.

Q. HAVE YOU PERFORMED A COST-OF-SERVICE SENSITIVITY INCORPORATING ALL YOUR DEMAND ALLOCATION FACTOR RECOMMENDATIONS?

A. Yes. Exhibit 602 to this testimony is the summary page from the Company cost-of-service model modified to reflect my recommendations. The following table compares the revenue to cost ratio (or "parity ratio") from the Company's study and the PIIC for the major customer classes. The parity ratio is the most appropriate yardstick for determining whether the rate schedule charges are

equitable to each customer class. It is a statistic that takes into account both the operating expenses and the rate base needed to serve each customer class. The relationship between operating expense and rate base will vary depending upon the utilization of facilities (or load factor) for each class. For example, a class with a low load factor will require a larger rate base investment relative to operating expense. On the other hand, a class with a high load factor will require more operating expense as compared to rate base investment. As the parity ratio includes both the return on rate base and the operating expenses of each class, it is the most accurate measure to use in rate spread determinations. A parity ratio less than 1.0 or 100% indicates a class is not paying its fair share of costs. Conversely, a ratio greater than 100% indicates the class is paying charges in excess of its cost responsibility.

Parity Ratio Comparison		
Class	Company	PIIC
Residential	105%	104%
Residential - TOD	99%	97%
General Service - Large	100%	103%
General Service - High Voltage	99%	102%
Irrigation	104%	105%
Street & Area Lighting	145%	130%
Space Heating	102%	97%
General Service - Small	103%	103%
Contract 1	94%	94%
Contract 2	97%	108%
State of Idaho	100%	100%

The difference in parity ratios for all major customers classes changes only slightly from the Company's study. The largest parity change between the two

studies is for the lighting class, but the PIIC parity ratio is still quite high at 130%.

IV. RATE SPREAD

Q. HOW IS THE COMPANY PROPOSING TO RECOVER ANY REVENUE INCREASE GRANTED BY THE COMMISSION IN THIS PROCEEDING?

A. The Company proposal tracks the results of its cost of service study very closely. The noted exception is for the lighting class where the Company is proposing no rate decrease for this class even though the cost study indicates it would be justified. For the lighting class, the Company is proposing no rate change at this time.

Q. DO YOU SUPPORT THE COMPANY'S RATE SPREAD PROPOSAL?

A. I support the objective of achieving cost-based rates. However, the Company's cost-of-service study should not be used for determining an equitable rate spread in this proceeding. Instead, the PIIC cost study should be used as the foundation to achieve a cost-based rate spread in this proceeding. The following table compares the cost-base rate spreads from the Company and PIIC study at the full increase sought by the Company.

Cost-Based Increase Comparison			
Company Proposed Price Increase - $000			
Class	Company Study	PIIC Study	Difference
Residential	$3,167	$3,781	$614
Residential - TOD	$3,236	$3,607	$371
General Service - Large	$3,000	$2,357	($644)
General Service - High Voltage	$741	$572	($169)
Irrigation	$3,852	$3,443	($410)
Street & Area Lighting	($165)	($108)	$57
Space Heating	$65	$97	$32
General Service - Small	$1,345	$1,455	$110
Contract 1	$11,741	$12,340	$599
Contract 2	$715	$155	($561)
State of Idaho	$27,698	$27,698	$0

Q. WHAT IS YOUR SPECIFIC RATE SPREAD RECOMMENDATION?

A. The following table presents my specific recommendation along with the Company proposal for comparative purposes at the Company's full request amount. As shown by the table, the PIIC recommendation gives no increase to the lighting rate schedules and a cost-based increase to all other classes.

Rate Spread Comparison ($000)			
Class	Company Proposal	PIIC Recommendation	Difference
Residential	$3,135	$3,766	$632
Residential - TOD	$3,219	$3,593	$374
General Service - Large	$2,984	$2,348	($636)
General Service - High Voltage	$737	$570	($167)
Irrigation	$3,820	$3,430	($390)
Street & Area Lighting	$0	$0	$0
Space Heating	$64	$97	$32
General Service - Small	1,335	$1,450	$115
Contract 1	$11,696	$12,294	$598
Contract 2	$712	$154	($558)
State of Idaho	$27,702	$27,702	$0

Q. HOW WOULD YOU ALLOCATE THE COMPANY'S RATE INCREASE?

A. The rate increase should be spread to the various classes using the following percentages.

PIIC Recommended Allocation	
Class	Rate Spread Percentages
Residential	13.60%
Residential - TOD	12.97%
General Service - Large	8.47%
General Service - High Voltage	2.06%
Irrigation	12.38%
Street & Area Lighting	0.00%
Space Heating	0.35%
General Service - Small	5.23%
Contract 1	44.38%
Contract 2	0.56%
State of Idaho	100.00%

The percentages were derived from the PIIC rate spread recommendation at the

1 Company's full request amount.

V. INDUSTRIAL RATE DESIGN

2 **Q. HOW IS THE COMPANY PROPOSING TO RECOVER THE REVENUE**
3 **INCREASE ASSIGNED TO INDUSTRIAL SCHEDULE 6, 6A AND 9**
4 **CUSTOMERS?**

5 **A.** The Company's rate design increases the demand charges by a larger percentage
6 than the energy charges. Specifically, under the Company's full request, the
7 demand charges for Schedules 6 and 6A are being increased by about 17% while
8 the energy charges are being increased by 12%. For Schedule 9, the demand
9 charges are increased by 21% while the energy charge is being increased by 12%.

10 **Q. DOES PIIC SUPPORT THIS RATE DESIGN PROPOSAL FOR THE**
11 **INDUSTRIAL SCHEUDLES?**

12 **A.** Yes. The Company's cost-of-service model aggregates the costs allocated to
13 these schedule into three categories that are extremely useful for rate design
14 purposes. These categories are: customer, energy, and demand. A comparison of
15 the per unit costs for the demand and energy categories from the cost study with
16 the per unit revenue recovery from the industrial schedules provides valuable
17 information on how to assign any schedule's rate increase. In the instant case,
18 this comparison shows that the Company's proposal is justified—the demand
19 charges should be given a greater percentage increase than the energy charges.
20 PIIC supports the Company's industrial rate design proposal in this proceeding.

21 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

22 **A.** Yes, it does.

Case. No. PAC-E-10-07
Exhibit No. 601
Witness: Donald W. Schoenbeck

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Donald W. Schoenbeck

Qualifications of Donald W. Schoenbeck

October 14, 2010

QUALIFICATIONS AND BACKGROUND OF DONALD W. SCHOENBECK

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A.** Donald W. Schoenbeck, 900 Washington Street, Suite 780, Vancouver,
3 Washington 98660.

4 **Q. PLEASE STATE YOUR OCCUPATION.**

5 **A.** I am a consultant in the field of public utility regulation and I am a member of
6 Regulatory & Cogeneration Services, Inc. ("RCS").

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
8 **EXPERIENCE.**

9 **A.** I have a Bachelor of Science Degree in Electrical Engineering from the University
10 of Kansas and a Master of Science Degree in Engineering Management from the
11 University of Missouri.

12 From June of 1972 until June of 1980, I was employed by Union Electric
13 Company in the Transmission and Distribution, Rates, and Corporate Planning
14 functions. In the Transmission and Distribution function, I had various areas of
15 responsibility, including load management, budget proposals and special studies.
16 While in the Rates function, I worked on rate design studies, filings and exhibits
17 for several regulatory jurisdictions. In Corporate Planning, I was responsible for
18 the development and maintenance of computer models used to simulate the
19 Company's financial and economic operations.

20 In June of 1980, I joined the consulting firm of Drazen-Brubaker &
21 Associates, Inc. Since that time, I have participated in the analysis of various
22 utilities for power cost forecasts, avoided cost pricing, contract negotiations for

gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Maryland, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

Case. No. PAC-E-10-07
Exhibit No. 602
Witness: Donald W. Schoenbeck

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Donald W. Schoenbeck

PIIC Cost Of Service Summary

October 14, 2010

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Idaho
12 Months Ending December 2010
PIIC Cost-of-Service Study
5.79% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	Parity Ratio
1	01	Residential	$39,005,158	6.96%	1.20	$37,512,791	$20,666,828	$2,342,754	$10,228,598	$4,172,372	$102,238	(1,492,367)	-3.83%	104%
2	36	Residential - TOD	$20,624,289	4.84%	0.84	$21,296,798	$12,816,735	$1,354,510	$5,542,979	$1,528,534	$54,042	672,509	3.26%	97%
3	06, 35	General Service - Large	$20,075,670	6.52%	1.13	$19,570,981	$15,191,253	$1,692,458	$2,491,117	$143,053	$53,100	(504,689)	-2.51%	103%
5	09	General Service - High Voltage	$5,062,482	6.32%	1.09	$4,978,443	$4,494,609	$444,555	$15,510	$10,475	$13,294	(84,039)	-1.66%	102%
6	10	Irrigation	$39,845,737	7.25%	1.25	$37,982,626	$24,118,596	$2,478,646	$11,108,344	$171,808	$105,232	(1,863,111)	-4.68%	105%
7	07,11,12	Street & Area Lighting	$600,521	24.58%	4.25	$461,978	$116,278	$10,843	$289,439	$43,829	$1,589	(138,543)	-23.07%	130%
8	19	Space Heating	$534,219	4.97%	0.86	$550,112	$375,670	$42,590	$119,133	$11,299	$1,420	15,893	2.97%	97%
9	23	General Service - Small	$12,309,609	6.52%	1.13	$11,995,507	$7,614,694	$885,547	$2,665,060	$797,498	$32,709	(314,102)	-2.55%	103%
10	SPC	Contract 1	$59,524,497	3.78%	0.65	$63,547,726	$57,384,734	$5,914,803	$94,737	($1,691)	$155,143	4,023,229	6.76%	94%
11	SPC	Contract 2	$4,466,432	8.57%	1.48	$4,151,651	$3,735,117	$308,676	$95,618	$525	$11,715	(314,781)	-7.05%	108%
12	Total	State of Idaho	$202,048,614	5.79%	1.00	$202,048,614	$146,514,515	$15,475,383	$32,650,535	$6,877,701	$530,480	(0)	0.00%	100%

Footnotes :

Column C : Annual revenues based on 12 months ending December 2010.
Column D : Calculated Return on Ratebase per December 2010 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Idaho
12 Months Ending December 2010
PIIC Cost-of-Service Study
8.36% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	$39,005,158	6.96%	1.20	$42,785,771	$22,957,163	$3,354,958	$12,082,714	$4,200,335	$190,600	$3,780,613	9.69%
2	36	Residential - TOD	$20,624,289	4.84%	0.84	$24,231,098	$14,160,206	$1,940,259	$6,506,044	$1,538,578	$86,012	$3,606,809	17.49%
3	06, 35	General Service - Large	$20,075,670	6.52%	1.13	$22,432,258	$16,869,104	$2,419,049	$2,942,664	$143,927	$57,514	$2,356,588	11.74%
5	09	General Service - High Voltage	$5,062,482	6.32%	1.09	$5,634,445	$4,955,979	$636,431	$17,830	$10,489	$13,716	$571,963	11.30%
6	10	Irrigation	$39,845,737	7.25%	1.25	$43,288,449	$26,540,739	$3,548,195	$12,906,056	$175,109	$118,351	$3,442,712	8.64%
7	07,11,12	Street & Area Lighting	$600,521	24.58%	4.25	$492,566	$127,334	$15,630	$302,343	$44,224	$3,035	-$107,955	-17.98%
8	19	Space Heating	$534,219	4.97%	0.86	$631,240	$417,139	$60,887	$140,086	$11,386	$1,741	$97,021	18.16%
9	23	General Service - Small	$12,309,609	6.52%	1.13	$13,764,712	$8,478,101	$1,266,312	$3,167,365	$802,728	$50,205	$1,455,103	11.82%
10	SPC	Contract 1	$59,524,497	3.78%	0.65	$71,864,800	$63,153,246	$8,449,044	$104,755	-$2,300	$160,055	$12,340,303	20.73%
11	SPC	Contract 2	$4,466,432	8.57%	1.48	$4,621,147	$4,058,861	$443,573	$106,217	$501	$11,995	$154,715	3.46%
12	Total	State of Idaho	$202,048,614	5.79%	1.00	$229,746,486	$161,717,872	$22,134,338	$38,276,074	$6,924,978	$693,224	$27,697,872	13.71%

Footnotes :
Column C : Annual revenues based on 12 months ending December 2010.
Column D : Calculated Return on Ratebase per December 2010 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per December 2010 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Case. No. PAC-E-10-07
Exhibit No. 603
Witness: Donald W. Schoenbeck

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Donald W. Schoenbeck

Rocky Mountain Power's Response to IIPA's Data Request 2

October 14, 2010

IIPA Data Request 2

Please answer the following with respect to information contained on Paice's Exhibit 49, Tab 5 "Cost of Service Allocation Factors":

A. Are the times of the system peaks listed on page 6 the same as the actual coincident system peaks during each of those months?

B. Are the times listed on page 6 on Pacific or Mountain time?

C. How do the total jurisdictional values for each month on page 6 relate to the Idaho values on McDougal's Exhibit 2, Tab 10?

D. With respect to the data listed on pages 7 and 12, which data came from the Company's load research data and which data came from census data? If from load research data, over what timeframe was the data collected? If the data came from load research data, but was adjusted, please provide an electronic copy of all workpapers and/or calculations that support the adjustments to actual values.

E. With respect to the data listed on page 13, which data came from the Company's load research data and which data came from billing data? If the data came from billiing data, but was adjusted, please provide an electronic copy of all workpapers and/or calculations that support the adjustments to actual values.

F. What was the level of curtailment/interruption for each customer class or Monsanto during the times of each of the monthly peaks listed on page 7? (Please specify at input level.)

G. Is there any weather normalization of the Distribution Peak data on page 12 or the Non-Coincident Peak data on page 13? If this data is weather normalized, please provide an electronic as well as hard copy of all workpapers used to support this normalization.

Response to IIPA Data Request 2

A. Yes.

B. Mountain time.

C. Please refer to the Company's response to IIPA Data Request 8.

D.

Schedule 001	Load Research Data	Jan09-Dec09
Schedule 036	Load Research Data	Jan09-Dec09

Schedule 006	Load Research Data	Jan09-Dec09
Schedule 023	Load Research Data	Jan09-Dec09
Schedule 019	Load Research Data	1996, 1998, 1999
Schedule 010	Load Research Data	'05-'09 Irrig. Seasons
Schedule 009	Census Data	Jan09-Dec09
Contract 1	Census Data	Jan06-Dec08
Contract 2	Census Data	Jan09-Dec09

Please refer to Attachment IIPA 2d for a listing of adjustments to actual values.

E.

Schedule 001	Est. From Load Research Data	Jan06-Dec08
Schedule 036	Est. From Load Research Data	Jan06-Dec08
Schedule 006	Est. From Load Research Data	Jan06-Dec08
Schedule 023	Est. From Load Research Data	Jan06-Dec08
Schedule 019	Est. From Load Research Data	Jan06-Dec08
Schedule 010	Est. From Load Research Data	Jan06-Dec08
Schedule 009	Est. From Load Research Data	Jan06-Dec08
Contract 1	Est. From Load Research Data	Jan06-Dec08
Contract 2	Est. From Load Research Data	Jan06-Dec08
Schedule 007	Billing Data	
Schedule 011	Billing Data	
Schedule 012	Billing Data	

Please refer to Attachment IIPA 2d for a listing of adjustments to actual values.

F. Please refer to the Company's responses to IIPA Data Requests 15 and 16(b).

G. There is no weather normalization of the distribution peak data or non-coincident data.

Recordholder: C. Craig Paice / Scott D. Thornton
Sponsor: C. Craig Paice

Factors Needed to Adjust Load Research kWh to Operating Statement kWh.

Kwh Sample	200901	200902	200903	200904	200905	200906	200907	200908	200909	200910	200911	200912	Total
ID RES 01	42,720,338	36,388,857	35,286,685	28,483,300	25,567,157	23,125,957	27,958,123	29,502,369	27,807,091	32,341,842	35,856,733	44,083,818	389,122,270
Pricing Kwh	46,113,921	38,151,027	35,964,683	32,158,584	28,004,536	27,444,432	28,439,454	31,213,964	28,166,100	27,185,703	32,787,445	44,903,767	400,533,616
Adj. Fact.	1.079437176	1.048426088	1.01921399	1.129032942	1.095332422	1.186737137	1.017216141	1.058015511	1.0129107	0.840573737	0.914401348	1.018599773	1.029325862
ID RES 36	35,035,873	29,790,154	29,373,872	23,132,781	19,055,820	16,122,023	17,781,685	16,529,999	14,739,735	19,751,620	23,383,657	32,098,964	276,796,183
Pricing Kwh	40,096,459	33,171,801	30,264,788	26,452,115	21,542,908	17,760,424	17,519,534	17,628,085	16,921,320	16,953,474	23,762,296	35,477,204	297,550,408
Adj. Fact.	1.144440129	1.113515593	1.03033022	1.143490487	1.130515926	1.101625026	0.985257246	1.066429889	1.148007071	0.858333342	1.016192463	1.105244518	1.074980171
ID GS 06S	26,663,545	22,287,645	22,719,898	21,427,964	22,408,039	20,268,211	22,427,566	21,822,536	22,289,106	24,210,797	23,270,359	24,955,476	274,751,142
Pricing Kwh	27,640,023	25,099,600	24,373,886	23,120,453	22,548,843	23,957,736	23,715,375	25,572,092	23,903,936	24,394,842	24,985,219	28,168,678	297,480,683
Adj. Fact.	1.036622212	1.126166538	1.072799094	1.078985059	1.006283638	1.18203506	1.05742081	1.17182036	1.072449294	1.007601774	1.07369289	1.128757392	1.08272774
ID GS 06P	286,265	239,652	243,925	230,055	239,658	217,270	241,900	236,467	241,523	263,161	252,939	272,312	2,965,127
Pricing Kwh	4,676,375	3,820,873	3,247,620	3,443,474	3,956,956	3,709,780	3,454,219	3,729,727	3,382,930	3,934,506	3,787,648	4,250,938	45,395,046
Adj. Fact.	16.3358252	15.94342213	13.31401045	14.96804677	16.51084462	17.07451558	14.27953286	15.7727167	14.00665775	14.95094638	14.97455118	15.61054232	15.30964643
ID GS 009	9,255,216	8,710,007	9,300,005	8,073,788	9,363,037	8,493,885	9,134,002	9,672,027	10,131,240	9,108,313	9,299,728	9,582,885	110,124,133
Pricing Kwh	9,764,754	9,337,431	9,568,569	8,844,734	9,302,394	8,954,392	8,966,088	10,650,779	10,187,673	10,086,760	9,840,260	11,031,534	116,535,368
Adj. Fact.	1.055054145	1.072034845	1.028877834	1.095487521	0.993523149	1.054216298	0.981616601	1.101194093	1.005570197	1.107423515	1.05812342	1.151170446	1.058218256
ID GS 23S	12,316,330	10,735,023	11,060,132	9,419,663	10,809,262	10,918,667	13,147,638	10,854,450	11,304,684	14,189,787	14,447,533	16,988,938	146,192,107
Pricing Kwh	15,359,807	13,662,963	13,173,364	12,129,272	11,017,261	11,658,551	11,693,336	12,780,700	11,870,345	12,304,503	13,611,611	16,580,156	155,841,869
Adj. Fact.	1.247109082	1.272746505	1.191067521	1.287654558	1.019242664	1.067763217	0.889386861	1.177461741	1.050037754	0.867137963	0.942140849	0.975938343	1.066007408
ID GS 23P	23,418	20,487	21,078	17,876	20,300	20,524	24,826	20,465	21,300	26,696	27,154	31,739	275,863
Pricing Kwh	21,881	22,284	17,912	20,806	43,263	134,451	140,823	137,527	120,920	46,356	22,787	33,749	762,759
Adj. Fact.	0.934366726	1.08771416	0.849795996	1.163906914	2.131182266	6.550916001	5.672399903	6.720107501	5.676995305	1.736439916	0.839176549	1.063329027	2.764992043
ID GS 019	2,855,964	2,527,234	1,565,138	1,142,286	860,617	806,652	839,917	798,975	860,509	1,190,802	1,777,294	2,303,363	17,528,751
Pricing Kwh	1,210,758	1,031,935	919,897	707,823	479,729	339,229	299,223	313,250	292,298	317,365	577,598	974,295	7,463,400
Adj. Fact.	0.423940218	0.408325861	0.587741784	0.619654797	0.557424499	0.420539464	0.356253058	0.392064833	0.339680352	0.266513661	0.324987312	0.42298804	0.425780479
ID IRR AV	16,695	7,143	49,164	45,259	34,365,553	90,291,423	157,449,003	97,205,200	68,308,177	31,822,368	408,859	21,063	479,989,907
Pricing Kwh	16,696	7,145	49,167	45,256	34,365,554	82,230,065	115,297,370	152,077,009	80,318,070	31,822,370	408,861	21,065	496,658,628
Adj. Fact.	1.000059898	1.000279994	1.00006102	0.999933715	1.000000029	0.910718452	0.7322839	1.564494585	1.175819258	1.000000063	1.000004892	1.000094953	1.034727232
ID ST 007	35,102	35,103	35,085	34,955	34,922	35,037	35,139	34,922	34,977	34,824	34,731	37,347	422,144
Pricing Kwh	34,732	34,184	34,231	34,163	34,253	34,172	34,177	34,186	34,025	33,988	33,988	33,990	410,091
Adj. Fact.	0.989468233	0.973825733	0.975662517	0.97734443	0.980851768	0.975308386	0.972634299	0.978933388	0.97278139	0.975995511	0.978619	0.910110316	0.971448025
ID ST 011	11,360	9,928	9,928	10,075	9,928	9,926	9,946	9,921	9,928	9,928	9,928	9,974	120,770
Pricing Kwh	11,323	11,171	8,748	8,705	8,816	8,908	8,908	8,914	8,908	8,906	8,917	9,006	111,230
Adj. Fact.	0.996741489	1.12520145	0.881144239	0.86402936	0.887954309	0.897441064	0.895636437	0.898518859	0.897260274	0.897063198	0.898153997	0.902947664	0.921005311
ID ST 012	159,447	159,601	162,531	160,250	161,273	161,477	162,122	161,344	162,354	161,798	161,828	200,076	1,974,101
Pricing Kwh	178,548	179,641	182,681	179,625	184,653	191,094	191,547	191,575	195,773	196,684	196,749	198,766	2,267,336
Adj. Fact.	1.11979417	1.125564219	1.123976349	1.120906418	1.144969892	1.183410622	1.181501209	1.187369843	1.205840346	1.215614326	1.215790239	0.99345273	1.148540949
Contract 2	7,506,507	6,875,801	7,369,341	6,862,930	7,586,323	7,061,910	4,710,529	7,733,615	8,772,544	8,611,509	8,943,444	9,515,453	91,549,906
Opt Stmts	7,518,000	6,871,200	7,375,200	6,854,400	7,602,000	7,056,000	4,704,000	7,744,800	8,769,600	8,643,600	8,920,800	9,517,200	91,576,800
Adj. Fact.	1.001531072	0.999330842	1.000795051	0.998757091	1.002066482	0.999163116	0.998613956	1.001446284	0.999664407	1.003726525	0.997468089	1.000183596	1.000293763
Contract 1	103,453,168	104,885,872	91,161,952	82,156,816	67,825,968	49,387,296	72,958,928	45,056,144	62,402,144	108,131,128	121,261,056	121,258,256	1,029,938,728
Opt Stmts	103,743,467	104,350,167	92,106,500	82,533,817	68,247,833	49,425,750	73,719,933	44,984,183	62,040,333	107,386,717	122,891,750	122,637,667	1,034,068,117
Adj. Fact.	1.002806088	0.994892493	1.010361209	1.004588794	1.00621982	1.000778621	1.010430599	0.998402867	0.994201951	0.993115661	1.013447796	1.011375811	1.004009354

Factors Needed to Adjust Pricing kWh to 2010 Test Period kWh.

Kwh Sample	200901	200902	200903	200904	200905	200906	200907	200908	200909	200910	200911	200912	Total
ID RES 01	46,113,921	38,151,027	35,964,683	32,158,584	28,004,536	27,444,433	28,439,454	31,213,964	28,166,100	27,185,703	32,787,445	44,903,767	400,533,617
Fore. Kwh	45,786,020	38,693,784	38,628,175	32,557,400	30,028,850	28,686,552	32,505,148	32,001,559	28,723,523	33,862,497	39,307,124	47,126,367	427,906,999
Adj. Fact.	0.992889327	1.014226537	1.074058542	1.012401541	1.072285218	1.045259416	1.142959636	1.025232136	1.019790564	1.245599461	1.198846815	1.049496961	1.068342283
ID RES 36	40,096,460	33,171,801	30,264,788	26,452,115	21,542,908	17,760,424	17,519,534	17,628,085	16,921,320	16,953,474	23,762,296	35,477,203	297,550,408
Fore. Kwh	35,898,717	29,955,437	28,385,730	22,710,685	18,638,604	15,622,652	16,815,275	15,659,994	14,573,813	18,791,057	26,472,247	36,882,559	280,406,770
Adj. Fact.	0.895308876	0.903039198	0.937912737	0.858558389	0.86518515	0.87963285	0.959801495	0.88835479	0.861269297	1.10838978	1.114044149	1.039612938	0.94238409
ID GS 06S	27,640,023	25,099,600	24,373,886	23,120,453	22,548,843	23,957,736	23,715,375	25,572,092	23,903,936	24,394,842	24,985,219	28,168,679	297,480,684
Fore. Kwh	22,381,943	20,506,620	23,326,380	22,344,242	22,727,983	22,864,005	23,891,382	22,999,534	20,147,374	23,072,114	23,220,975	24,515,500	271,998,050
Adj. Fact.	0.809765718	0.817009832	0.957023434	0.966427496	1.007944538	0.95434747	1.007421623	0.89939978	0.842847564	0.945778362	0.929388472	0.870310597	0.914338527
ID GS 06P	4,676,376	3,820,875	3,247,624	3,443,471	3,956,959	3,709,784	3,454,216	3,729,729	3,382,927	3,934,504	3,787,643	4,250,943	45,395,051
Fore. Kwh	3,786,768	3,121,691	3,108,048	3,327,868	3,988,392	3,540,419	3,479,855	3,354,516	2,851,294	3,721,171	3,520,196	3,699,637	41,499,855
Adj. Fact.	0.809765545	0.817009405	0.957022255	0.966428338	1.007943774	0.954346441	1.007422498	0.899399298	0.842848312	0.945778843	0.929389699	0.870309604	0.91419338
ID GS 009	9,764,754	9,337,431	9,568,569	8,844,734	9,302,394	8,954,392	8,966,088	10,650,779	10,187,673	10,086,760	9,840,260	11,031,534	116,535,368
Fore. Kwh	8,681,660	8,837,284	8,375,961	9,902,460	9,903,737	9,258,792	8,443,165	9,359,435	8,181,521	8,936,767	8,014,523	8,590,740	106,486,046
Adj. Fact.	0.889081313	0.946436343	0.875361934	1.119588214	1.064643937	1.033994504	0.941677645	0.878755906	0.803080493	0.885989871	0.814462569	0.778743901	0.913765908
ID GS 23S	15,359,808	13,662,963	13,173,364	12,129,272	11,017,261	11,658,551	11,693,336	12,780,700	11,870,345	12,304,503	13,611,611	16,580,156	155,841,870
Fore. Kwh	15,255,607	12,993,291	13,421,314	12,039,598	11,765,500	11,008,133	12,251,369	12,300,009	11,544,660	12,486,202	12,984,704	14,400,365	152,450,752
Adj. Fact.	0.993216013	0.950986299	1.018822096	0.992606834	1.067915161	0.944211052	1.047722328	0.962389327	0.972563154	1.014766863	0.953943193	0.8685301	0.978240007
ID GS 23P	21,881	22,284	17,912	20,806	43,264	134,450	140,821	137,525	120,921	46,356	22,787	33,749	762,756
Fore. Kwh	21,733	21,192	18,249	20,652	46,201	126,950	147,543	132,355	117,602	47,041	21,738	29,312	750,567
Adj. Fact.	0.993216078	0.950986299	1.018822096	0.992606834	1.067890478	0.944218074	1.047737165	0.962403353	0.972555111	1.014766863	0.953943193	0.8685301	0.98402019
ID GS 019	1,210,758	1,031,935	919,897	707,823	479,729	339,229	299,223	313,250	292,298	317,365	577,598	974,295	7,463,400
Fore. Kwh	1,103,577	861,408	924,916	697,030	504,539	343,708	384,038	437,503	366,919	428,752	658,508	1,057,994	7,768,893
Adj. Fact.	0.911476232	0.834749869	1.005456381	0.98475233	1.051717709	1.013202035	1.283451982	1.396656307	1.255291162	1.350975064	1.140079769	1.0859075	1.040932106
ID IRR AV	16,696	7,145	49,167	45,256	34,365,554	82,230,065	115,297,370	152,077,009	80,318,070	31,822,370	408,861	21,065	496,658,628
Fore. Kwh	0	0	0	13,142,767	61,976,524	120,213,362	157,510,798	119,441,664	56,474,885	14,370,000	1,670,000	490,000	545,290,000
Adj. Fact.	0	0	0	290.4093766	1.803448995	1.461914959	1.366126551	0.785402508	0.703140459	0.451569132	4.084517721	23.26133397	1.097917099
ID ST 007	34,732	34,184	34,231	34,163	34,253	34,171	34,177	34,187	34,025	33,988	33,988	33,989	410,088
Fore. Kwh	30,527	28,799	31,967	31,977	33,522	32,941	35,117	32,345	33,245	36,472	35,573	32,767	395,252
Adj. Fact.	0.878944305	0.842474467	0.933864395	0.93600649	0.978664546	0.96399716	1.027500219	0.946122519	0.977071182	1.073080634	1.046633949	0.964036963	0.963821937
ID ST 011	11,323	11,171	8,748	8,705	8,816	8,908	8,908	8,914	8,908	8,906	8,917	9,006	111,230
Fore. Kwh	9,227	8,106	8,419	8,283	8,500	8,275	8,377	8,290	8,397	8,328	8,323	8,151	100,676
Adj. Fact.	0.814907503	0.725613944	0.962426542	0.95153133	0.964124317	0.928899274	0.940376327	0.929968624	0.942675061	0.935113152	0.933402449	0.905104374	0.905118878
ID ST 012	178,548	179,642	182,682	179,625	184,652	191,094	191,547	191,575	195,773	196,684	196,749	198,766	2,267,337
Fore. Kwh	205,705	177,623	200,436	190,265	202,010	189,754	191,951	189,816	192,148	197,243	190,208	186,174	2,313,333
Adj. Fact.	1.152099041	0.988759746	1.097187336	1.05923455	1.094004954	0.99298754	1.002108472	0.990818832	0.981482173	1.002842646	0.966755984	0.936648096	1.020286431
Contract 2	7,518,000	6,871,200	7,375,200	6,854,400	7,602,000	7,056,000	4,704,000	7,744,800	8,769,600	8,643,600	8,920,800	9,517,200	91,576,800
Fore. Kwh	9,450,000	8,500,000	8,500,000	8,500,000	8,500,000	7,000,000	8,500,000	8,500,000	8,500,000	8,500,000	8,500,000	8,500,000	101,450,000
Adj. Fact.	1.25698324	1.237047386	1.152511118	1.240079365	1.118126809	0.992063492	1.806972789	1.097510588	0.969257435	0.983386552	0.952829343	0.893119825	1.107813333
Contract 1	121,970,700	99,054,193	113,510,492	115,685,463	116,177,840	114,983,390	111,071,360	98,179,270	109,851,853	118,620,660	104,876,900	110,406,126	1,334,388,247
Fore. Kwh	126,687,520	107,468,880	113,268,067	113,350,513	113,353,837	114,426,193	117,990,270	118,022,077	114,371,070	114,533,550	116,169,197	115,532,137	1,385,173,311
Adj. Fact.	1.038671747	1.084950336	0.997864294	0.979816392	0.975692413	0.995154109	1.062292476	1.202107909	1.041139197	0.965544704	1.107671918	1.046428683	1.038058687

Case. No. PAC-E-10-07
Exhibit No. 604
Witness: Donald W. Schoenbeck

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Donald W. Schoenbeck

Rocky Mountain Power's Response to IIPA's Data Request 8

October 14, 2010

IIPA Data Request 8

On Exhibit 2, page 10.13 there is a different coincident peak value for Idaho (406) for January 2010 than the value used on Exhibit 49 pages 6 and 7. Please provide all data, equations, and assumptions used to develop the figure on both Exhibit 2 and Exhibit 49. Please supply this data in Excel format. Explain how, if at all, the jurisdictional data from Exhibit 49 (pages 6 and 7) flows through or is incorporated in Exhibit 2 Tab 10.

Response to IIPA Data Request 8

Idaho jurisdiction loads on Exhibit 2, page 10.13 were developed from adjusted state jurisdictional loads as explained in Company witness Peter C. Eelkema's testimony. Class loads on Exhibit 49, Tab 5, pages 6 and 7 were developed from both sample and direct census Load Research data. Therefore, because they are from different data sources and used for different purposes, class loads do not directly flow through to the Idaho state jurisdiction load.

Please refer to Attachment IIPA 8a for the support for class loads and Attachment IIPA 1f for support for page 10.13 of Exhibit 2.

Recordholder: C. Craig Paice
Sponsor: C. Craig Paice