Williams · Bradbury

ATTORNEYS AT LAW

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IDAHO PUBLIC
UTILITIES COMMISSION

November 14, 2012

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Re: PAC-E-12-12

Dear Ms. Jewell:

Please find enclosed an original and seven copies of Comments of the PacifiCorp Idaho Industrial Customers for filing in the above referenced case.

Thank you for your assistance in this matter. Please feel free to give me a call should you have any questions.

Sincerely,

Ron Williams

Ronald L. Williams

RLW/jr
Enclosures

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Attorneys for PIIC

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO CANCEL SCHEDULE NO. 17 AND IMPLEMENT A NEW PARTIAL REQUIREMENTS TARIFF	**Case No. PAC-E-12-12** COMMENTS OF THE PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

COMES NOW the PacifiCorp Idaho Industrial Customers (PIIC) and submits these comments regarding the request by Rocky Mountain Power (RMP) to implement a new Schedule 31, Partial Requirements Tariff.

1. Background. The members of PIIC are industrial customers and large power users that receive electrical service from RMP under rate Schedules 6, 6A, 9, 23, 23A and Special Contract No. 2 (Agrium/Nu West). One of PIIC's members, BYU-Idaho, recently approached RMP concerning partial requirements electrical service, in conjunction with BYU-Idaho's plan to upgrade its thermal facilities in Rexburg, Idaho.

For more than 50 years BYU-Idaho has produced its own heat for campus buildings, using coal as its fuel source. BYU-Idaho is currently in the process of designing and hopes to soon start construction on a new central heating station for its campus in Rexburg, Idaho. This new plant will use natural gas instead of coal as it fuel source, and will cogenerate both steam for campus heating and electricity.

A 4.7 MW gas fired turbine generator will run continuously at BYU-Idaho and will be fitted with a heat recovery boiler that will use the waste exhaust heat from the turbine to produce a constant supply of steam for heating campus buildings. The heat recovery boiler will have additional gas burners to augment the waste heat with additional gas-fired heat, to meet winter peak loads. There will also be two additional steam boilers installed for redundant heat needs in case of emergency or extreme cold conditions, when additional heat is needed above what can be produced by the heat recovery boiler. BYU-Idaho will also be installing underground fuel tanks for alternative (back-up) fuel supply to both the turbine and the boilers, along with 2 diesel generators for emergency needs or cold startup of the turbine. BYU-Idaho is currently in discussions with RMP about buying power from and selling power to RMP.

2. Recommendations. Attached to this filing is the analysis of RMP's proposed Schedule No. 31, prepared by PIIC's retained consultant in this case, Mr. Donald Schoenbeck, of Regulatory and Cogeneration Services, Inc. (RCS). PIIC submits these recommendations prepared by RCS, which are attached hereto. To briefly summarize the RCS report, PIIC recommends:

a. That RMP be required to revise proposed Tariff 31 by:

(i) Eliminating the Excess Power Service from the proposed tariff, including all rates, terms and conditions,

(ii) Revising the Back-up Facilities rates in the proposed tariff to be the values shown on the attached RCS report, Table 4 (Summer: $5.16; Winter: $3.90),

(iii) Revising the daily Back-up rates in the proposed tariff to the values shown in the attached RCS report, Table 7 (Summer: $0.17; Winter: $0.13),

(iv) Revising the applicability of the Back-up Power rates to only on-peak periods of Monday through Friday, 7 AM to 11 PM, and

(v) Revising the Scheduled Maintenance Power rate to be set a $0.00.

b. That with the five revisions above implemented, Schedule 31 be allowed to go into effect, on an interim basis, but that this docket remain open.

c. That RMP be ordered to submit studies that determine the costs it incurs in providing Partial Requirements, Back-up and Scheduled Maintenance services to partial requirements customers in Idaho.

d. That the Commission issues an additional scheduling order providing:

(i) The date on which RMP would submit additional cost based studies for Partial Requirements service,

(ii) Adequate time for additional discovery by interested parties, including PIIC, and

(iii) A second date on which parties can submit written comments on RMP's second proposed Schedule 31, based on the cost studies to be provided.

WHEREFORE, the PacifiCorp Idaho Industrial Customers request that the Commission issue an order extending.

DATED: This 14th day of November, 2012.

Ronald L. Williams

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 14th day of November, 2012, I caused to be served a true and correct copy of the foregoing document upon the following individuals in the manner indicated below:

Ted Weston **Rocky Mountain Power** 201 South Main, Suite 2300 Salt Lake City, UT 84111 E-Mail: ted.weston@pacificorp.com	☐ Hand Delivery ☐ US Mail (postage prepaid) ☐ Facsimile Transmission ☐ Federal Express ☒ Electronic Transmission
Daniel E. Solander **Rocky Mountain Power** 201 South Main Street, Suite 2300 Salt Lake City, UT 84111 E-Mail: daniel.solander@pacificorp.com	☐ Hand Delivery ☐ US Mail (postage prepaid) ☐ Facsimile Transmission ☐ Federal Express ☒ Electronic Transmission
Data Request Response Center **PacifiCorp** E-Mail: datarequest@pacificorp.com	☒ Electronic Transmission
Randall C. Budge Racine, Olson, Nye, Budge & Bailey, Chtd. P.O. Box 1391; 201 E. Center Pocatello, ID 83204-1391 E-Mail: rcb@racinelaw.net Attorneys for **Monsanto**	☐ Hand Delivery ☐ US Mail (postage prepaid) ☐ Facsimile Transmission ☐ Federal Express ☒ Electronic Transmission
Brubaker & Associates 16690 Swingley Ridge Rd., #140 Chesterfield, MO 63017 E-mail: bcollins@consultbai.com **Monsanto Consultant**	☐ Hand Delivery ☐ US Mail (postage prepaid) ☐ Facsimile Transmission ☐ Federal Express ☒ Electronic Transmission
James R. Smith **Monsanto Company** P.O. Box 816 Soda Springs, ID 83276 E-Mail: jim.r.smith@monsanto.com	☐ Hand Delivery ☐ US Mail (postage prepaid) ☐ Facsimile Transmission ☐ Federal Express ☒ Electronic Transmission

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Ronald L. Williams

RCS

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November 9, 2012

VIA EMAIL

Mr. Ronald L. Williams
Williams Bradbury, P. C.
1015 W. Hays St.
Boise, ID 83702

RE: ID PAC-E-12-12

Dear Mr. Williams,

First of all, thank you for engaging the services of Regulatory & Cogeneration Services, Inc. ("RCS") on behalf of PacifiCorp Idaho Industrial Customers regarding the above referenced application of PacifiCorp (dba Rocky Mountain Power) to implement a partial requirements rate schedule in Idaho. RCS has extensive experience in the design of such tariffs having analyzed similar filings in several jurisdictions since the 1980s.

Attached to this transmittal letter are three documents: an Executive Summary of the RCS recommendations regarding the filing, detailed comments and conclusions on the filing, and a brief description of my background and experience.

If you have any questions regarding my recommendations or comments, please do not hesitate to contact me.

Sincerely,

REGULATORY & COGENERATION SERVICES, INC.

Donald W. Schoenbeck

Donald W. Schoenbeck

Enclosures

RCS

Regulatory & Cogeneration Services, Inc.

RCS, Inc. Executive Summary and Recommendations
On the Application of Rocky Mountain Power to Implement Schedule 31
(Case No. PAC-E-12-12)

On August 13, 2012, Rocky Mountain Power ("Company") filed an application at the Idaho Public Utilities Commission ("Commission") seeking the authorization to cancel the existing Standby Service schedule (Schedule No. 17) and implement a new Partial Requirements Service – High Voltage schedule (Schedule No. 31). The proposed Schedule 31 would apply to customers with on-site generation, who are served at transmission voltage and with a load of up to 15,000 kilowatts ("kW"). The otherwise applicable tariff for such customers that do not have on-site generation in Idaho is Schedule 9. Regulatory & Cogeneration Services, Inc. ("RCS") was retained by the PacifiCorp Idaho Industrial Customers ("PIIC") to analyze the Company's filing and provide recommendations regarding the proposed Schedule 31. This executive summary presents the conclusions and recommendations of RCS from having analyzed the filing, the cost-of-service study ("cost study") used to drive the proposed charges from PAC-E-11-12, and responses to data requests submitted by PIIC.

RCS appreciates the Company's effort to implement a partial requirements tariff in its Idaho service territory that provides Back-up Service, Maintenance Service and Supplemental Service as required by PURPA. However, the RCS analysis has revealed several aspects of the proposed schedule that are inconsistent with the Public Utility Regulatory Policy Act of 1978 ("PURPA") requirements for such a tariff. In particular, the proposed tariff includes an "Excess Power Service" for power in excess of the customer's contract demand. The proposed demand charges for this service are twice the otherwise applicable full requirements service (Schedule 9) charge. PURPA requires that sales be:

> *(i) Shall be just and reasonable and in the public interest; and*
>
> *(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. 18 C.F.R. § 292.305(a)(1)*

As the Excess Power rates, terms and conditions are inconsistent with PURPA and do not apply to full requirements customers under the otherwise applicable tariff, the punitive Excess Power service should not be part of the Company's proposed Schedule 31.

The Company's proposed rate charges for Back-up Service and Scheduled Maintenance Service are derived from the cost of serving full requirements customers and not customers with on-site generation. PURPA requires that:

> *(c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power:*

> *(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and*
>
> *(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities. 18 C.F.R. § 292.305*

Ignoring these fundamental directives has resulted in the Company deriving proposed charges for Back-up and Maintenance service that are too high and inconsistent with PURPA.

RCS recommends the proposed Schedule 31 tariff be approved on an interim basis with the modifications listed below. However, the interim tariff should only be effective for a set period of time which will allow the Company to submit the necessary studies that will allow the Commission to appropriately determine the actual costs the Company incurs in providing Partial Requirements Back-up and Scheduled Maintenance services to partial requirements customers. The Commission should direct the Company to produce a cost study that must take into account the reliability of the on-site generation facilities and the likely timing of back-up service needs and the cost of providing coordinated scheduled maintenance service during off-peak and/or low load periods. This study should be submitted as part of this docket, with its schedule extended, or in a separate follow-on docket. In either case, all parties should be afforded the opportunity to examine the Company study and be granted the necessary time to submit additional discovery in order to obtain the necessary data that would allow for the complete development of alternative partial requirement proposals.

The specific changes that can and should be made in the interim to the proposed Schedule 31 demand charges to make the tariff more closely aligned with PURPA are:

1. The Excess Power Service contained in the tariff must be eliminated, including all rates, terms and conditions.
2. The interim Back-up Facilities rates should be: Summer: \$5.16; Winter: \$3.90
3. The interim daily Back-up Power rates should be Summer: \$0.17; Winter: \$0.13
4. The interim Back-up Power rates are only applicable during the on-peak period of Monday – Friday 7 am to 11 pm.
5. The interim Schedule Maintenance Power rate should be \$0.00

The following table is a comparison summary of the Schedule 31 rate charges as proposed by the Company with the RCS interim rate recommendations.

Executive Summary Comparison
Schedule 31 Demand Charges

	Company Proposal	RCS Proposal	Difference - Amount	Difference - Percent
Back-up Facilities Rate				
Summer	$5.97	$5.16	($0.81)	-14%
Winter	$4.51	$3.90	($0.61)	-14%
Back-up Power Rate				
Summer	$0.18	$0.17	($0.01)	-6%
Winter	$0.13	$0.13	$0.00	0%
Scheduled Maintenance Rate				
Summer	$0.090	$0.00	($0.09)	-100%
Winter	$0.065	$0.00	($0.065)	-100%
Excess Power Rate				
Summer	$20.52	Eliminate		
Winter	$15.48	Eliminate		

RCS

Regulatory & Cogeneration Services, Inc.

RCS, Inc. Comments
On the Application of Rocky Mountain Power to Implement Schedule 31
(Case No. PAC-E-12-12)

INTRODUCTION

On August 13, 2012, Rocky Mountain Power ("Company") filed an application at the Idaho Public Utilities Commission ("Commission") seeking the authorization to cancel the existing Standby Service schedule (Schedule No. 17) and implement a new Partial Requirements Service – High Voltage schedule (Schedule No. 31). The proposed Schedule 31 would apply to customers with on-site generation and who are served at transmission voltage (44,000 volts or higher) and with a load of up to 15,000 kilowatts ("kW"). The otherwise applicable rate tariff for such customers that do not have on-site generation in Idaho is Schedule 9.

Regulatory & Cogeneration Service, Inc ("RCS") was asked by the PacifiCorp Idaho Industrial Customers ("PIIC") to review the filing and provide any thoughts or concerns regarding the proposed services or the specific rate charges. The next three sections of these comments address the proposed services offered under the schedule, the specific rate charges under this proposed schedule and the RCS recommendations for correctly implementing a partial requirements service schedule in the Company's Idaho service territory.

SCHEDULE 31 SERVICE OFFERINGS

The proposed Schedule 31 provides for Back-up Service, Maintenance Service, Supplemental Service and Excess Power Service. Back-up service provides power to the customer's on-site load when its self-generation is unavailable due to a forced outage. Similarly, Maintenance Service provides power to the customer's on-site load when the generator is down or unavailable due to a maintenance outage. Supplemental Service provides power to the customer's on-site load that is in excess of its own generation. (In other words, if a customer has an on-site load of 12,000 kW but only a 10,000 kW generator, the Supplemental Service would provide the additional 2,000 kW to meet the on-site power needs.) Finally, the Excess Power Service being proposed by the Company charges a customer for service in excess of the customer's contract demand amount.

Under most circumstances, the Public Utility Regulatory Policy Act of 1978 ("PURPA") requires utilities to provide supplemental power, back-up power and maintenance power (18 C.F.R. § 292.305b). As these three services are included in the Company's proposed Schedule 31, it is appropriate to replace the existing Schedule 17 with a tariff such as Schedule 31 to be consistent with and fulfill the PURPA requirement. However, the Excess Power Service being proposed by the Company as part of Schedule 31 is not called for under PURPA nor is this same provision contained within Schedule 9. Further, the Company is proposing that the Excess Power rate be twice (two times) the otherwise applicable Schedule 9 demand charge, making it a punitive rate, as opposed to a cost-based service. This is contrary to PURPA, which requires that rates for sales to partial requirements customers:

> *(i) Shall be just and reasonable and in the public interest; and*
>
> *(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. 18 C.F.R. § 292.305(a)(1)*

As the Excess Power rates, terms and conditions are inconsistent with PURPA and do not apply to full requirements customers under the otherwise applicable tariff, the punitive Excess Power service should not be part of the Company's proposed Schedule 31.

SCHEDULE 31 – SPECIFIC RATE CHARGES

Back-up Service

The specific Schedule 31 Back-up service charges consist of a Back-up Facilities Rate and a Back-up Power Rate as shown in the following table. The billing unit for the Back-up Facilities rate being proposed by the Company is the amount of power agreed to be provided by the Company but it cannot exceed the output capacity of the customer's on-site generation. As such, it is a fixed monthly contract demand amount. The billing unit for the Back-up Power rate is the highest 15 minute interval of Back-up power supplied by the Company each day. The Company's proposed charges for Back-up Service are set forth in Table 1.

Table 1
Back-Up Service Charges

Back-up Facilities Rate - $/kW	
Summer	$5.97
Winter	$4.51
Back-up Power Rate - $/kW/Day	
Summer	$0.18
Winter	$0.13

Back-up Facilities Rate

As proposed by the Company, the Back-up Facilities Rate is based on 100% of the per unit demand-related transmission cost and 13% of the per unit generation demand-related costs allocated to Schedule 9 customers as contained in the cost-of-service study ("cost study") from Case No. PAC-E-11-12. Table 2 shows the derivation of the proposed Back-up Facilities Rates.

Table 2
Schedule 9 Cost Assignment
Case No. PAC-E-11-12

Description	**Demand Costs**	**NCP kW**	**Per Unit**
13% of Generation Costs	$247,241	225,153	$1.10
100% Transmission Costs	$931,409	225,153	$4.14
Annual Back-up Facilities Rate:			$5.24
Summer Rate (Annual x 114%)			**$5.97**
Winter Rate (Annual x 86%)			**$4.51**

There is a significant inconsistency between the value used in the above table to derive the per unit charges and the corresponding billing unit being proposed by the Company. The 225,153 kW value used in the Company's calculation is the summation of the 12 monthly hourly non-coincident peaks ("NCP") from the Company's cost study for all Schedule 9 customers. The monthly hourly values range from 17,416 kW to 20,725 kW over the 12 month period. However, the Company's proposed billing unit for the Back-up Facilities rate is a contract demand amount which will not vary from month to month. Consequently, the NCP factor used by the Company is too low for two reasons. First, the Company has not incorporated the difference between an hourly versus a 15 minute demand interval. Second, it did not recognize that the contract demand would be the maximum amount of Back-up power the customer could ever require. Table 3 corrects for these inconsistencies and presents a more appropriate denominator for deriving the per unit Back-up Facilities rate charges.

Table 3
Back-Up Facilities Billing Unit Derivation

Description	**kW**
Highest Schedule 9 NCP Hourly Value	20,725
Contract Demand (Max NCP x 12)	248,695
Adjust for Hourly v 15 Minute Interval:	105%
Back-up Facilities Demand Estimate:	260,532

The calculation in Table 3 is based on the highest Schedule 9 monthly NCP value of 20,725 kW coupled with an adjustment of 105% to convert an integrated hourly demand value to a 15 minute interval. The adjustment was calculated by using the Schedule 9 billing demand units (which are based on the highest 15 minute interval) from Case No. PAC-E-11-12 (235,870 kW) divided by the 12 month NCP hourly demands. Using this estimated Back-up Facilities Demand produces the Back-up Facilities charges shown in Table 4.

Table 4
Back-Up Facilities Rates with
Estimate Contract Demand Billing Units

Description	**Demand Costs**	**CD kW**	**Per Unit**
13% of Generation Costs	$247,241	260,532	$0.95
100% Transmission Costs	$931,409	260,532	$3.58
Annual Back-up Facilities Rate:			$4.53
Summer Rate (Annual x 114%)			**$5.16**
Winter Rate (Annual x 86%)			**$3.90**

The costs used by the Company in deriving the Back-up Facilities rates fail to properly implement PURPA. Specifically, PURPA directs that:

> *(c) <u>Rates for sales of back-up and maintenance power</u>. The rate for sales of back-up power or maintenance power:*
>
> *(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and*
>
> *(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities. 18 C.F.R. § 292.305*

Section 292.305(c)(1) of PURPA requires that rates for back-up service take into account the specific forced outage characteristics of the on-site generators and prohibits the Company from simply assuming that the outages will occur at the time of the system peak.

On-site generation facilities are highly reliable. BYU Idaho, the specific PIIC member referred to in the Company's application as the "recent customer inquiry" regarding partial requirements, is installing a small gas fired turbine with an expected 95% operating availability. This means that on average, this facility, and others like it, will need back-up service, because of a forced outage, only about 5% of the time. This in turn suggests the facility only has about a 5% chance of needing back-up power during the system peak period. However, the Company has derived the proposed back-up service rates using the cost of serving high load factor full requirements customers on Schedule 9. Based on the coincident and non-coincident allocation factors from the Company's cost study, the customers on Schedule 9 have a 72% coincidence factor (12 CP demand of 162,815 kW / 12 NCP demand of 225,153 kW = 72%). In other words, the Company's proposed Back-Up Facilities per unit service rate is based on the assumption that the customer would be requiring service 72% of the peak period hours even though the generator will only require back-up service about 5% of the year. Thus, the Company has ignored the PURPA directive to take into the account the timing of when a customer needs back-up service. This critical short-coming in the Company's cost study cannot be readily corrected. It would take much more time than has been provided in this docket to produce a study which analyzed and derived cost-based back-up charges based upon the likely timing needs for the service.

A properly designed back-up service rate should not only take into account the specific back-up needs of the on-site generators but the associated cost of providing the service. The costs that should be included and recovered through back-up service rates fall into two categories: local delivery-related costs and system costs. Local delivery costs are the transmission and distribution cost that are incurred by the utility in order to provide the necessary delivery service to the customer. Frequently, these costs are actually paid for by the self-generation customer as part of the interconnection process. However, if there are local delivery costs that have not been paid for through the interconnection payment, it would be reasonable to recover these costs through a monthly facilities charge. System costs are generation and bulk transmission costs (network transmission) which are incurred in order to provide service to sales or wheeling customers during peak periods. The proper allocation and recovery of these system costs to a partial requirements customer is dependent upon the peak utilization of these facilities by the customers.

Unfortunately, at the present time no Idaho customers are taking stand-by service, so the expected service requirements are not known. Two possible ways to estimate the need for and the cost of back-up service are to use the expected forced outage rate of the customer's generator(s), or the Company's experience with providing back-up service in its other service territories. As noted by the Company, it has several customers taking partial requirements services in the states of Utah and Wyoming. An analysis of the Utah customers for 2008 through 2010 suggests a system peak coincidence value in the range of 4% - 14%, a value substantially below the 72% value implicitly employed by the Company by using the coincident demand of full requirement customers.

The Company has explicitly acknowledged that the costs incurred to provide service to a partial requirements customer is not the same as a full requirements customer with regard to generation system costs. For generation costs, the Company is proposing that only 13% of the demand-related generation costs assigned to Schedule 9 customers be recovered in the Back-up Facilities rate. However, the Company has made no such adjustment with regard to its transmission costs. The Company has a vast transmission system that provides both system-wide and local delivery service. Unfortunately, the Company's cost study does not differentiate the costs associated with each functional use making it impossible at this time to determine a reasonable segmentation of the transmission system costs for recovery in the Back-up Facilities rates. But a cost-based value should be far below the 100% assumption used by the Company in its proposal.

Back-up Power Rate

The Company has derived the daily Back-up Power Rate as the difference between the Schedule 9 demand charges and the Back-up Facilities rates coupled with an adjustment factor to approximate the difference between daily and monthly billing demands. The derivation of the Company's proposed rates are shown in Table 5

Table 5
Derivation of the Proposed
Back-up Power Rate - $/kW/Day

Description	Summer	Winter
Schedule 9 Demand Charge	$10.26	$7.74
Back-up Facilities Charge	$5.97	$4.51
Difference:	$4.29	$3.23
Conversion Factor Daily/Monthly	80.0%	80.0%
Daily Back-Up Power rate:	$0.18	$0.13

Since the Company has equated the Back-up Power charges to the difference between the Schedule 9 demand charges and the back-up Facilities charge, the Company has not derived a cost-based back-up service as required under PURPA. In fact, due to the Company's use of an 80% conversion factor, a partial requirements customer needing a constant level of back-up service for 30 days could pay more than a comparable full requirements customer as shown by Table 6.

Table 6
30 Days of Back-up Power
Effective Monthly Demand Charge

Description	Summer	Winter
Schedule 9 Full Requirements	$10.26	$7.74
Schedule 31 Partial Requirements	$11.37	$8.41
Difference	$1.11	$0.67

This result violates PURPA. At a minimum, the Company's proposed conversion factor should be eliminated or set to a value of 100% thereby making the effective demand charge for 30 days of back-up service the same or less than as that paid by a full requirements customer. Table 7 shows the recommended calculation using the Back-up Facilities rates from Table 4.

Table 7
Derivation of Back-up Power Rates
$/kW/Day

Description	**Summer**	**Winter**
Schedule 9 Demand Charge	$10.26	$7.74
Back-up Facilities Charge	$5.16	$3.90
Difference:	$5.10	$3.84
Conversion of Daily to Monthly	100.0%	100.0%
Back-Up Power rate:	$0.17	$0.13

Finally, the Company's proposed Back-up Power charges are applied to the highest daily 15 minute interval irrespective of the day or time when it occurs. As generation and transmission demand related costs are incurred to meet customer demands during the peak periods, the Company's proposed charges should not apply during off-peak hours. This would be consistent with the Company's partial requirement tariffs in Utah and Wyoming where the rates are applied to the highest billing demand occurring between the hours of 7 am to 11 pm Monday through Friday.

Maintenance Service Rate

Under the Company's proposed tariff, maintenance service can be scheduled for up to a 30 day contiguous period or two 15 day periods subject to approval by the Company. During these scheduled maintenance periods, the Company is proposing that the customer pay one-half of the Back-up Power rate. Table 7 shows the Company proposal and the effective demand charge paid for scheduled maintenance service for periods of 15 and 30 days.

Table 8
Proposed Maintenance Rates
($/kW/Day)

Description	**Summer**	**Winter**
Back-Up Power Rate	$0.18	$0.13
Scheduled Maintenance Rate	$0.088	$0.066
Effective Rate for:		
15 Day Period	$1.32	$1.00
30 Day Period	$2.64	$1.99

Section 292.305(c)(2) of PURPA requires that rates for maintenance service shall take into account coordination with the utility's facilities. Schedule 31 requires that customer's provide the Company an indicative maintenance schedule each September 1st for eighteen months commencing on January 1st of the following year. A customer's maintenance service request may be modified by the Company and even canceled within seven days of the scheduled outage.

The Company's planning reserve margin is to have 13% reserves during peak load periods. As a consequence, during low load months and non-peak periods, the Company has reserves well above the planning reserve amount. By scheduling on-site maintenance during these low load and high reserve margin periods, no additional capacity costs are being incurred by the Company in providing the service. Given the level of coordination called for under the proposed terms of Schedule 31 and discretion of the Company, it is not appropriate to require any level of demand payment for generation and transmission system costs for scheduled maintenance service.

RCS RECOMMENDATIONS FOR IMPLEMENTING SCHEDULE 31

While most of the proposed services the Company has included under Schedule 31 are consistent with PURPA, the specific rate charges are not. As implementation of a partial requirements tariff structured in large part as the Company has proposed is a positive step. Consequently, RCS recommends the tariff be approved on an interim basis with the modifications listed below.

The interim tariff would be limited in time and only effective until such time that the Company submits a study to the Commission which determines the cost it incurs in providing Partial Requirements, Back-up and Scheduled Maintenance services to partial requirement customers in Idaho. After that filing, all parties should be afforded the opportunity to examine the Company study and be granted the necessary time to submit discovery in order to obtain the necessary data that would allow for the more accurate and complete development of alternative partial requirement proposals.

However, at this time there are a number of changes that can and should be made to the proposed Schedule 31 to make the tariff compliant with PURPA. These changes are:

1. The Excess Power Service contained in the tariff must be eliminated, including all rates, terms and conditions.
2. The interim Back-up Facilities rates should be the values shown in Table 4 (Summer: $5.16; Winter: $3.90)
3. The interim daily Back-up Power rates should be the values shown in Table 7 (Summer: $0.17; Winter: $0.13)
4. The interim Back-up Power rates are only applicable during the on-peak period of Monday – Friday 7 am to 11 pm.
5. The interim Schedule Maintenance Power rate should be $0.00

The following table is a comparison summary of the Schedule 31 charges as proposed by the Company with the RCS interim rate recommendations.

Table 9
Schedule 31 - Proposed Charge Comparison

	Company Proposal	RCS Proposal	Difference - Amount	Difference - Percent
Customer Service Charge	$370.00	$370.00	$0.00	0%
Back-up Facilities Rate				
Summer	$5.97	$5.16	($0.81)	-14%
Winter	$4.51	$3.90	($0.61)	-14%
Back-up Power Rate				
Summer	$0.18	$0.17	($0.01)	-6%
Winter	$0.13	$0.13	$0.00	0%
Scheduled Maintenance Rate				
Summer	$0.090	$0.00	($0.09)	-100%
Winter	$0.065	$0.00	($0.065)	-100%
Excess Power Rate				
Summer	$20.52	Eliminate		
Winter	$15.48	Eliminate		
Supplementary Demand Rate				
Summer	$10.26	$10.26	$0.00	0%
Winter	$7.74	$7.74	$0.00	0%
Supplementary Energy Rate				
Summer	3.8835	3.8835	$0.00	0%
Winter	3.8835	3.8835	$0.00	0%

RCS

Regulatory & Cogeneration Services, Inc.

QUALIFICATIONS AND BACKGROUND
OF
DONALD W. SCHOENBECK

Donald W. Schoenbeck has a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri. He has also completed all the course work for a Master of Science degree in Nuclear Engineering.

From June of 1972 until June of 1980, he was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, he had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, he worked on rate design studies, filings and exhibits for several regulatory jurisdictions involving both electricity and natural gas matters. In Corporate Planning, he was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, he joined the consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, he has participated in the analysis of various utilities for power cost forecasts, avoided cost pricing matters, 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, he formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. RCS has assisted 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.

Mr. Schoenbeck has 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, he has 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.