ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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IDAHO PUBLIC UTILITIES COMMISSION

November 2, 2006

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

PAC-E-03-14

Attention: Jean D. Jewell
Commission Secretary

Re: Idaho 2006 Irrigation Load Control Credit Rider Program Evaluation Report

PacifiCorp d.b.a. Rocky Mountain Power (the Company) hereby submits an original and eight copies of the 2006 Idaho Irrigation Load Control Credit Rider Program Evaluation Report. The purpose of this filing is to comply with Commission Order Nos. 29209 and 29416 and provide an annual evaluation of the Irrigation Load Control Credit Rider program.

The Company does not intend to make a separate application in 2006 to change the amount of the Schedule 72 Load Control Service Credit for the 2007 irrigation season. On May 24, 2006 the Company entered into an agreement with the Idaho Irrigation Pumpers Association that the tariff amount for 2007 will equal the current amount (subject to Commission approval, Docket No. PAC-E-06-4). However, per program specifications, the Company will notify all Schedule 10 customers of the 2007 credit level by January 15, 2007.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By Fax: (503) 813-6060

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah St., Suite 2000
Portland, OR 97232

Informal questions should be directed to Brian Dickman (801) 220-4975.

Sincerely,

D. Douglas Larson /p.r

D. Douglas Larson
Vice President, Regulation

Enclosures

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Schedule 72 Idaho Irrigation Load Control *Program*

2006 Credit Rider Initiative Final Report

23 October 2006

Table of Contents

Page

Background 1

2006 results 1

Cost effectiveness analyses 5

2005 cost effectiveness calculation error 6

Load profile data 7

Technical challenges 12

Measurement & Verification (M&V) processes 13

Crop type analysis 13

***Program* enhancements under consideration** 16

Background

Idaho Public Utilities Commission Order No. 29209 and Order No. 29416 in Case No. PAC-E-03-14 requires PacifiCorp dba Rocky Mountain Power (the Company) prepare an annual report on the *Idaho Irrigation Load Control Program (Program)*. Subsequent to 2003, reporting requirements include responses to the following:

1. The number of irrigation customers who were eligible to participate in the *Program*
2. The number of irrigation customers who entered into a load control *Service Agreement*
3. The number of irrigation customers who participated in the *Program* for the full three and one-half months
4. The number of irrigation customers who are not eligible to participate in the following year's *Program*
5. The total dollar amount of credits provided under the *Program* identified by month
6. Proposed changes and/or recommendations to improve the *Program*

2006 results

Table One details eligible 2006 Schedule 10 sites and customers (requirement #1)[1]. Table One also contains counts of customers and sites that entered into an actual load control contract (requirement #2). Details for *Program* years 2003, 2004 and 2005 are provided for comparison. The data presented in Table One reflect the number of irrigation customers and sites that participated in the *Program* for the full three and one-half months (requirement #3). In 2006, 20.1% of total available sites and 23.3% of the total available customers participated in the *Program*. There are zero customers NOT eligible to participate in 2007 (requirement #4).

Table One
Schedule 10 Eligible & Full-Year Participating Sites & Customers

	Participant Sites	Participant Customers
2003 Actual Participants	401	207
2004 Actual Participants	734	340
2005 Actual Participants	1,065	489
2006 Actual Participants	931	478
Eligible 2006 Counts	4,636	2,044
Customers NOT eligible to participate 2006	N/A	0

Note: based on 15 September reports

Unadjusted monthly participation credit amounts issued to 2006 *Program* participants are presented in Table Two (requirement #5). The total *Program* participation credits ($925,577.33) represent an 8.9% increase over 2005 credits. Table Two further presents the total amount of resource under contract at the time of credit issuance. Table Three presents a comparative analysis of credits issued for the 2003, 2004, 2005 and 2006 *Program* years. Here again, 2006 values are unadjusted. The reader should note that the Commission approved a ≈21% increase in

[1] Data are reported as of 15 September 2006. This notation is important as *Program* participants and subsequently loads change throughout the irrigation season as *Program* participation status may change as a function of agri-business, weather, crop type and/or equipment vagaries. Wherever possible and based on what the Irrigation Management Team has determined to be the most understandable way to communicate quantitative *Program* demographics and impacts, reporting date may change. Accordingly, and throughout this report the date for the specific quantitative result will be noted.

participation credits over the 2005 *Program* year. Despite increased participation credits there was no corresponding increase in participation sites. In fact, participation marginally waned (9.9% decrease in avoided MW; 12.58% decrease in the number of participating sites; 2.25% decrease in the number of participating customers)[2]. *Program* management has speculated as to the reason for this trend including the following:

1. Commodity prices for agricultural product / crop selection
2. Water / soil moisture considerations
3. 2005 premature timer failures

While it is not entirely clear, the fact of the matter is that the Irrigation Management Team can offer no definitive explanation for the *lower-than-expected-participation*. Meetings with growers were planned and executed to assess the whys and wherefores of grower participation with regards to the load control initiative. Moreover, and during the meetings with growers, consideration was given to discussing the potential use of a fully duplexed control technology that would permit dispatch options at the discretion of the Company (similar to the 2001 *Program* design). The result of these discussions and the pilot testing of the new control technology are discussed in the *Program Enhancements Under Consideration* section.

Further, it should be noted that the 2006 *Program* year-end report statistics are based on the *Program*'s transactional database. The database offers a 'snapshot' in time and does not take into consideration *Program* participants who may have elected to discontinue participation prior to 15 September. Hence, the statistical information may, if anything, understate *Program* impacts (particularly, avoided kW). For example, at the conclusion of the sign-up phase and the beginning of the dispatch period (1 June) the database recorded 50.8 MW firmed scheduled resource. At the conclusion of the irrigation season the database indicated an average peak avoided MW of 47.1, a difference of 3.7MW.

Table Two
2006 Participation Credits x Month

	June	July	August	September
Credits	$240,705.61	$317,825.54	$288,371.66	$78,674.52
kW Under Contract	82,652.6	100,131.8	95,321.8	81,127.7

Table Three
2003–2006 Comparative Participation Credits Issuance

Year	Total Participation Credits Issued
2003	$277,583.72
2004	$406,002.00
2005	$842,666.80
2006	$925,577.33

[2] Comparisons were based on the peak average difference as of 15 September.

Table Four introduces unadjusted 2006 *Program* costs. For years 2003, 2004 and 2005 *Program* costs are represented for comparative purposes. During 2006 100% of sites that participated in the Program during 2005 were visited to inspect equipment and identify faulty timers. As discussed in the *Technical Challenges* section of this report, during 2005 the Program experienced a high frequency of timer failure. The source of the problem was identified as a flawed board design. Working closely with the manufacturer (Grasslin, a German subsidiary of GE) and the local distributor (Consolidated Electric Company (CED); Logan, UT) timer change-outs were negotiated for the 2006 season. This change-out practice had a dramatic effect on customer service as there was less than 10 customer service calls (or < 1% of total timers installed) associated with equipment failures during 2006.

Table Four
Comparative Load Control *Program* Costs 2003, 2004, 2005 & 2006

Cost Category	2003 Costs (April '03–Sept '03)	2004 Costs Oct '03–Sept '04	2005 Costs Oct '04–Sept '05	2006 Costs Oct '05–Sept '06
Administrative support	$9,613.43	$1,665.29	$851.56	$194.60
Program evaluation	$2,135.43	$8,369.88	$377.50	$0.00
Field / Db admin. expenses	$250,222.98	$239,807.03	$326,061.01	$330,802.05
Participation credits	$277,583.72	$410,325.49	$842,666.80	$925,577.33
Program management	$10,992.99	$55,036.29	$54,826.69	$ 42,554.85
Reporting	$351.79	$1,940.00	$0.00	$0.00
Total Program costs	$550,900.34	$717,143.98	$1,224,783.56	$1,299,128.83

Note: 2003 costs over 6 month period; subsequent *Program*-year costs are calculated over a 12 month period

Table Five provides avoided kW statistics and participation site counts based on participation option (again note: data are current as of 15 September). A couple of observations are noteworthy. First, the three hour option was **not** a popular offer. The Irrigation Management Team met with growers and learned that the inconvenience and associated labor of having to accommodate a three-hour interruption was not offset by the participation credit. This was particularly noteworthy with larger growers. Nevertheless, the three hour dispatches were again important in demonstrating 'load shaping' capabilities. If modeling being undertaken by PacifiCorp's Commercial & Trading (C&T) organization shows that the 'load shaping' capabilities are sufficient to result in additional resource value, further enhancements in *Program* design may be warranted. For example, a pricing differential could be offered to growers to gain additional participation for a three-hour option. Bottom line, the reader should be cautioned to not unduly dismiss the low participation in the three hour blocks. It may be that these particular options have significant and measured value to the Company.

Second, the six hour dispatch blocks were, by far, the most popular option, representing 91% of total *Program* participation.

Table Five
Program Impacts by Participation Option

Participation Option	Site Ct.	June Avoided kW	July Avoided kW	Aug. Avoided kW	Sept. Avoided kW
I MW 2-8pm	411	35,708.2	43,557.7	41,605.9	34,931.9
I TTH2-8pm	437	35,151.6	43,869.5	41,314.0	36,016.9
II MW 3-6pm	11	895.7	957.9	939.6	835.2
II MW 4-7pm	9	1,268.4	1,495.4	1,417.0	818.6
II TTH 3-6pm	11	395.3	597.9	589.1	541.1
II TTH 4-7pm	7	631.8	789.2	656.3	453.7
III MWTTH 3-6pm	18	458.9	666.4	632.1	579.0
III MWTTH 4-7pm	20	699.9	825.7	710.1	682.4
IV M 2-8pm	7	2,358.4	3,052.0	2,996.7	2,850.8
Totals:	931	77,568.2	95,811.7	90,860.8	77,709.6

Note: data reported as of 15 September

Table Six transposes the data presented in Table Five into dispatch schedules. Table Six indicates the avoided kW by month, control day (Tuesday / Thursday) and by hour. Here also the reader should take into consideration that *Program* participants who discontinued participation prior to the 15 September time horizon are NOT reflected in these data. Hence these data understate the avoided kW that was actually realized at points earlier in the irrigation season. Table Seven mirror images data presented in Table Six with the exception that Table Seven reflects the Monday / Wednesday control period.

Table Six
2006 Avoided kW by Month, Tuesday / Thursday Ctrl. Day & Hour

JUNE Tuesday/Thursday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	35,151.6	36,005.8	37,337.5	37,337.5	36,483.3	35,151.6

JULY Tuesday/Thursday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	43,869.5	45,133.8	46,748.7	46,748.7	45,484.4	43,869.5

AUGUST Tuesday/Thursday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	41,314.0	42,535.2	43,901.6	43,901.6	42,680.4	41,314.0

SEPTEMBER Tuesday/Thursday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	36,016.9	37,137.0	38,273.1	38,273.1	37,153.0	36,016.9

Table Seven
2006 Avoided kW by Month, Monday / Wednesday Ctrl. Day & Hour

JUNE Monday/Wednesday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	35,708.2	37,062.8	39,031.1	39,031.1	36,408.1	35,708.2

JULY Monday/Wednesday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	43,557.7	45,182.0	47,503.1	47,503.1	44,383.4	43,557.7

AUGUST Monday/Wednesday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	41,605.9	43,177.6	45,304.7	45,304.7	42,316.0	41,605.9

SEPTEMBER Monday/Wednesday Avoided kW by Hour

Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	34,931.9	36,346.1	37,847.1	37,847.1	35,614.3	34,931.9

Cost effectiveness analyses

Based upon the cost and avoided MW values above together with the $/kW-yr avoided as provided by the 2004 IRP (and used in 2005 year end computations), cost effectiveness calculation were prepared for each of the four standard utility industry tests:

1. Total Resource Cost (TRC)
2. Utility
3. Ratepayer
4. Participant

The Program cost-effectiveness analysis is based on the ratio of the present value of the Program's benefits to costs and the net benefits (benefits minus costs), discounted at the appropriate rate for the various benefit/cost tests.[3] The benefits are based on the calculations as defined by the Capacity Expansion Model (CEM) and reported in the 2004 Integrated Resource Plan (IRP)[4]. The CEM selection of Schedule 72 at $27.19/kW-yr was based on 2003 / 2004 costs to deliver the Program. Costs used in these calculations include administrative costs, contractor (field technician and database design / administration), participant credits, and associated equipment costs. The participation credits are not included in the Total Resource Cost (TRC) test because they are a transfer payment from the utility to the participants.

The cost effectiveness of the Program was calculated by Quantec using a simplified spreadsheet analysis. This analysis multiplies average demand reductions for the June, July and August period as a result of customers participating in the Program, by the estimated value of avoided demand noted above. Again, this value is $27.19/kW-yr. This value is multiplied by 10% to account for the effect of line losses, resulting in a cost effectiveness calculation value of $29.91/kW-yr.

[3] Note that no discounting of costs or benefits was required in this analysis since all costs and benefits occurred in 2006.
[4] Chapter 8, p. 166, Table 8.26

Based on data from the Program in 2003 and 2004, PacifiCorp and Quantec examined whether energy savings, hence revenue losses, should be included in the analysis. This analysis showed that energy use is 'shifted' rather than 'avoided' hence zero energy savings were accrued for the Program and lost revenues are not included as a cost and energy savings are not applicable as indicated above. Accordingly, the benefits for the cost-effectiveness analysis are based on capacity savings alone and are presented in *Table Eight: 2006 Cost Effectiveness Analyses.*

As shown in Table Eight, the Schedule 72 passes the TRC Test. The Program also passes the Participant Test since the participant incurs no costs. As a result, the benefit/cost ratio would be infinite for the Participant Test and the value is indicated as 'N/A' in Table Eight.

Table Eight
2006 Cost Effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$1,246,330.86	$374,096.50	$872,234.36	3.33
Utility	$1,246,330.86	$1,299,673.83	($53,342.97)	0.96
Ratepayer	$1,246,330.86	$1,299,673.83	($53,342.97)	0.96
Participant	$925,577.33	$0.00	$925,577.33	N/A

2005 cost effectiveness calculation error

In the course of preparing 2006 cost effectiveness analyses it was discovered that the Company had inadvertently made two errors in the 2005 analysis. First, the $/kW-yr. value for a 'fully dispatchable' resource was mistakenly selected instead of the value for a 'firm scheduled forward' resource. The 'dispatchable' resource $/kW-year is $58.35 vs. $27.19 for the 'scheduled firm' resource. Second, in performing the calculations the units were mistakenly transposed. Instead of calculating cost effectiveness benefit stream on the basis of **$/kW**-yr they were calculated on **$/MW**-yr. In the 2005 Year-End Schedule 72 Report cost effectiveness values were reported as those indicated in Table Nine (below). These errors were corrected and cost effectiveness calculations recomputed. The results of these analyses are presented in Table Ten. Noteworthy is the change in TRC values. In 2005 the TRC was reported as 2.94. The corrected TRC value for 2005 is 3.81, a difference of 0.87.

Table Nine
Original Values Reported in 2005 Cost Effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$1,124,284	$382,117	$742,167	2.94
Utility	$1,124,284	$1,224,784	$ (100,499)	0.92
Ratepayer	$ 1,124,284	$1,224,784	$ (100,499)	0.92
Participant	$842,667	$0	$ 842,667	N/A

Table Ten
Corrected 2005 Cost Effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$1,455,484	$382,117	$1,073,367	3.81
Utility	$1,455,484	$1,224,784	$230,700	1.19
Ratepayer	$1,455,484	$1,224,784	$230,700	1.19
Participant	$ 842,667	$0	$842,667	N/A

Load profile data

Throughout the control period, Company SCADA data were collected and used in preparing impact analyses. Transmission Circuit Breaker #67 (CB-67 (Big Grassy)) aggregates four distribution substations (Hamer, Sandune, Camas and Dubois) which were known to have a significant number of *Program* participants. SCADA values were taken and logged at 120 second intervals. Log files from CB-67 were culled, data manipulated and subsequently plotted for the July / August period. A pivot table was prepared and data averages for day-of-week as well as for control vs. non-control periods were also calculated.

Illustration One (*Schedule 72 Idaho Irrigation Load Control-Average Daily Load Curve: Control vs. Non-Control Periods for July & August (CB 67-'Big Grassy'*) depicts (1) the average for all control days (Monday through Thursday, inclusive) and (2) the average for all non-control days (Friday through Sunday, inclusive). In addition to the load control dispatch, what is noteworthy is the load shifting effect as depicted in the difference between control and non-control days particularly during the non-dispatch hours. The reader will note that this 'gap' is wider in the evening and early morning hours. It is hypothesized that this trend in the 'gap' is a function of growers scheduling irrigation turns to minimize the effects of moisture loss resulting from transvaporation which, of course, is greater in the heat of the afternoon. Further note that the 'gap' narrows in the afternoon and in early evening hours.

Illustration One
Schedule 72 Idaho Irrigation Load Control-Average Daily Load Curve:
Control vs. Non-Control Periods for July & August (CB 67-'Big Grassy')

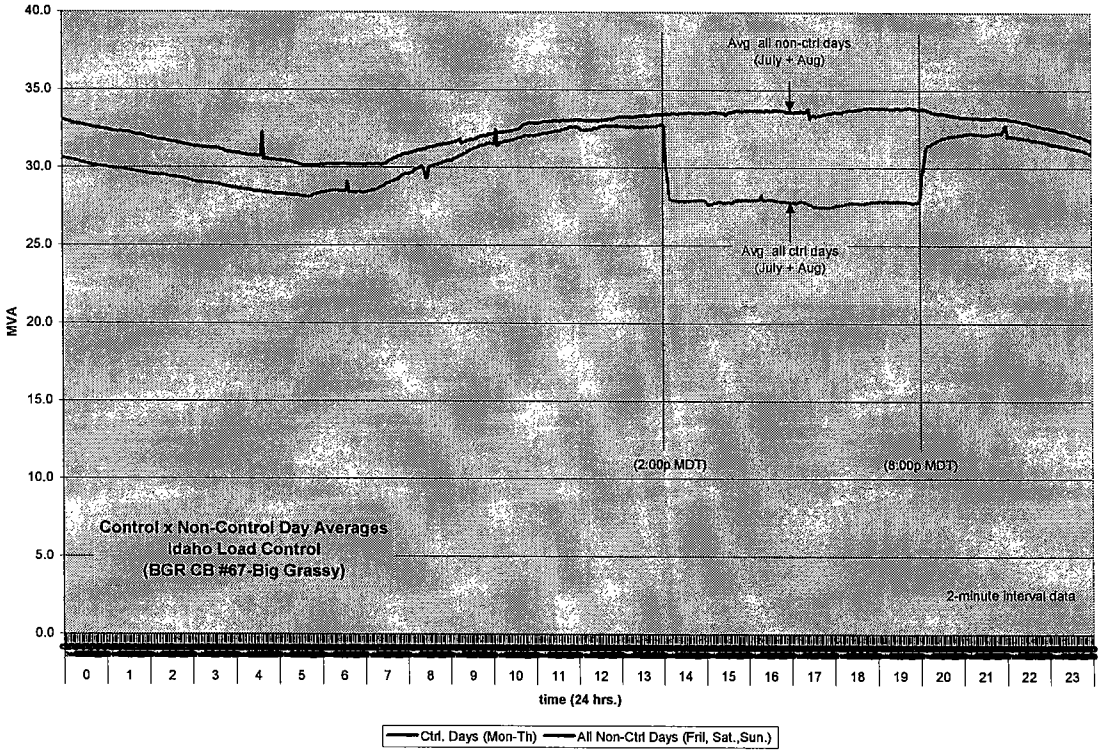


Illustration Two *(Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Control Average & Control Dispatch Schedule (M/W vs. TTH) Averages (CB 67-Big Grassy))* plots Big Grassy 120-second interval load data by the two principle control periods (M/W and T/TH). The overall average for all control days during the '06 July/August period is also plotted in Illustration Two. Highlighted is the six-hour dispatch block of the 'Dispatch Event'.

Illustration Two
Schedule 72 Idaho Irrigation Load Control-Daily Load Curve:
Control Average & Control Dispatch Schedule (M/W vs. TTH) Averages (CB 67-Big Grassy)

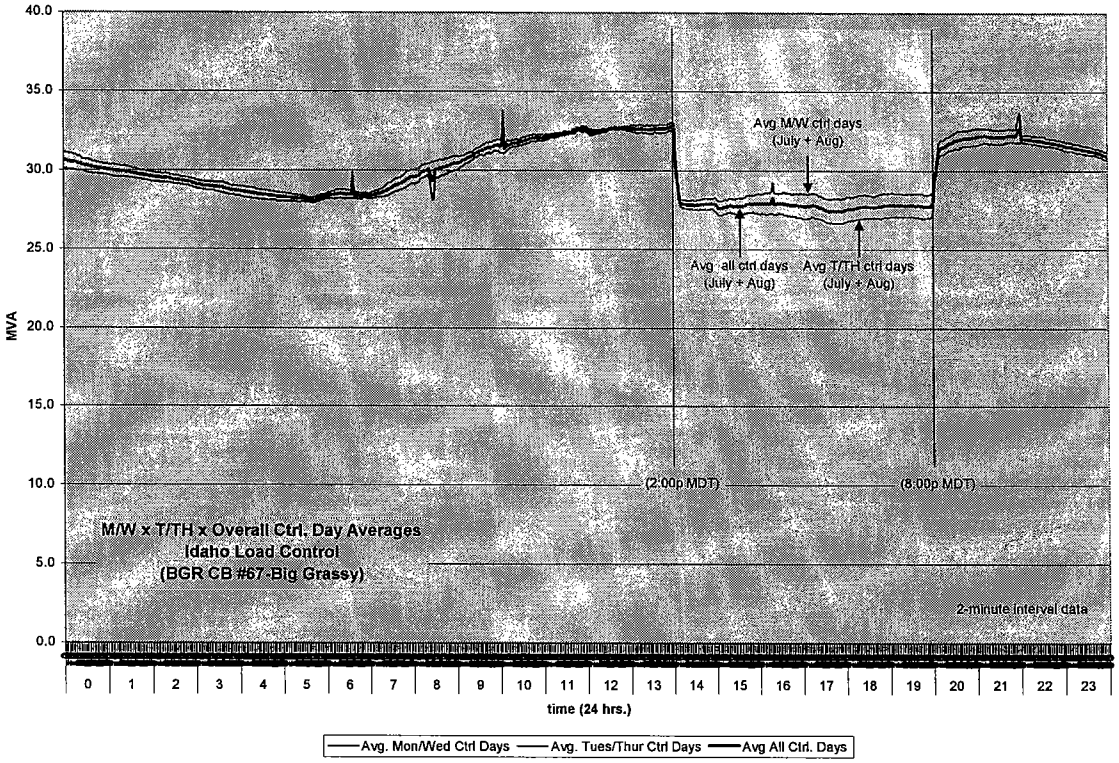


Illustration Three (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Individual Control Day-of-Week & Overall Average Control Days)* plots Big Grassy 120-second interval load data by individual day-of-week (ctrl days). Average daily control plots are also included in Illustration Three. Highlighted is the six-hour dispatch block and the impacts as a result of the 'Dispatch Events'. Tuesday recorded the greatest avoided demand than any other dispatch day. This finding was rewarding as, on average, the Company experiences the greatest demand on Tuesday. The reader should note that while the Company works hard to balance dispatch loads across all dispatch days, there is equal attention to accommodate grower preference for a particular dispatch option.

Illustration Three
Schedule 72 Idaho Irrigation Load Control-Daily Load Curve:
Individual Control Day-of-Week & Overall Average Control Days (CB 67-'Big Grassy')

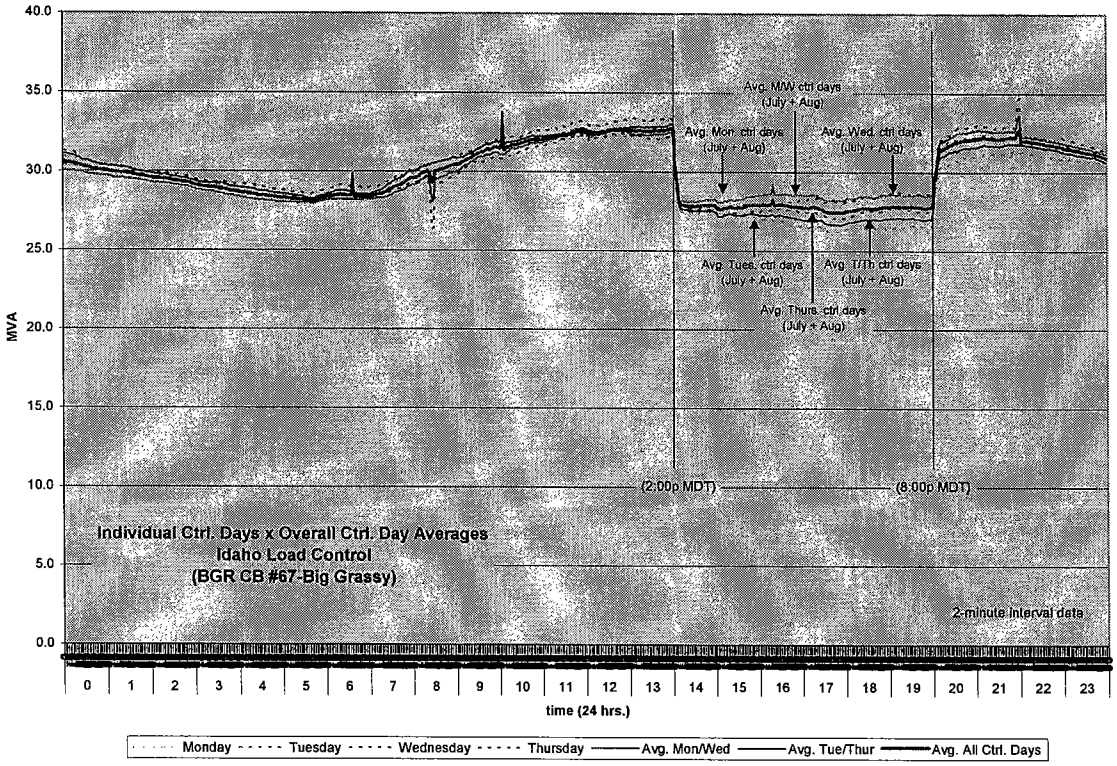


Illustration Four (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Control Average vs. Non-Control Days (CB 67-Big Grassy)*) plots Big Grassy 120-second interval load data by (1) individual non-control day-of-week, (2) average for all non-control days and (3) the average for all control days. Highlighted is the six-hour dispatch block and the resulting impacts of non-control days.

Illustration Four
Schedule 72 Idaho Irrigation Load Control-Daily Load Curve:
Control Average vs. Non-Control Days (CB 67-Big Grassy)

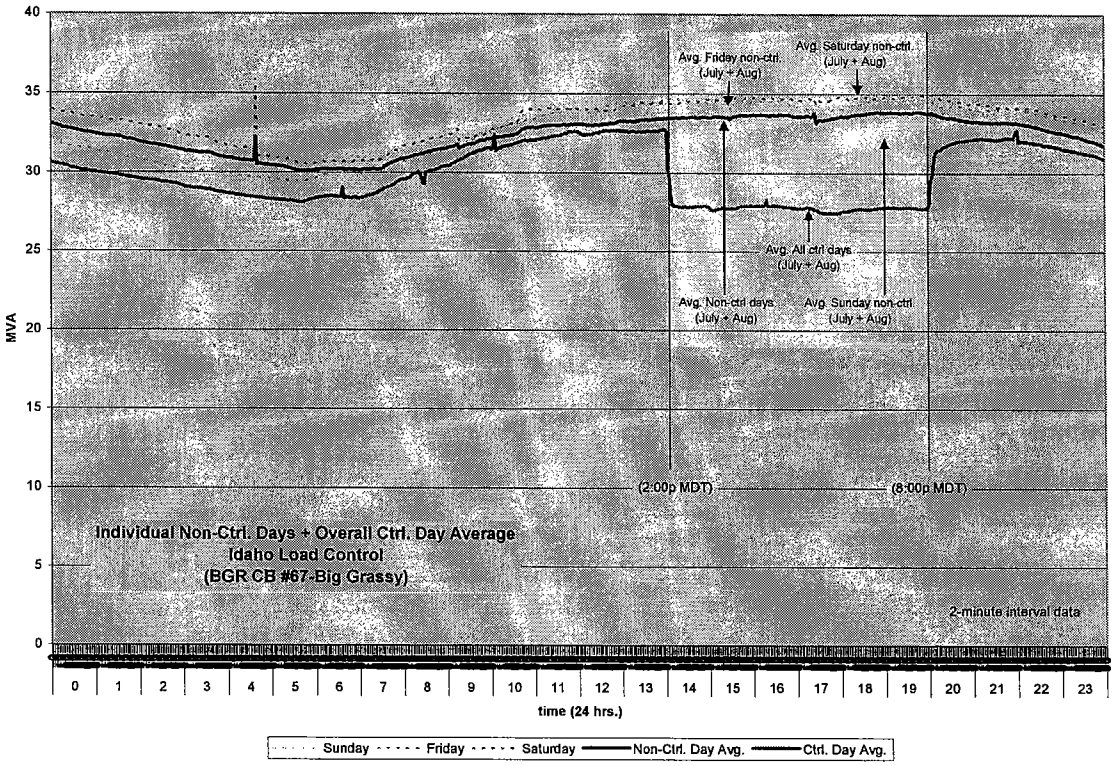
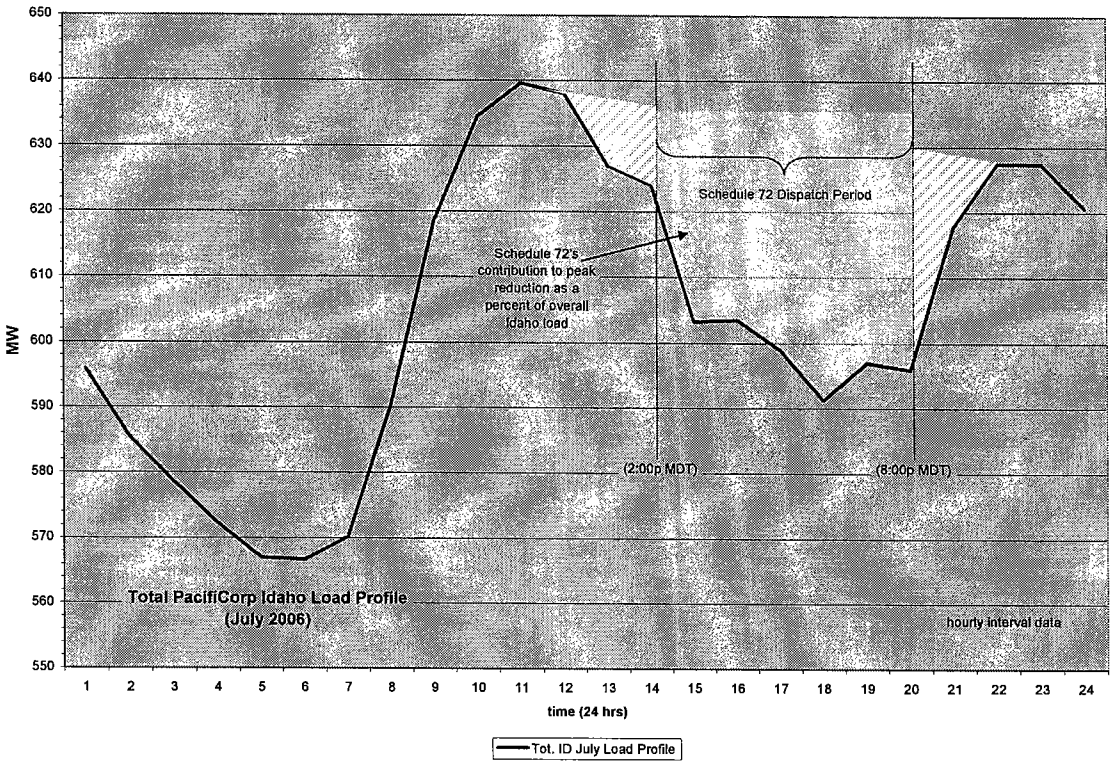


Illustration Five (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Total PacifiCorp Hourly Idaho Load (July) & Estimated Impact of Schedule 72)* plots the total Company average hourly interval load data for the month of July[5]. Also plotted is a 44MW decrement (estimated average avoided MW generated as a function of Schedule 72 across the 6 hr dispatch block). While Schedule 72 accounts for a measured 'dip' in the load profile, the Idaho load even without Schedule 72 would naturally be reduced in the afternoon hours (areas shaded in striped tan). The reason for this is that growers prefer to avoid irrigating in the heat of the day to minimize soil moisture loss as a function of transvaporation.

[5] Note: at the time of the preparation of this report data are not yet fully adjudicated for FERC reporting; nevertheless it is not anticipated there will be measured deviations from what is indicated in Illustration Five

Illustration Five
Schedule 72 Idaho Irrigation Load Control-Daily Load Curve:
Total PacifiCorp Hourly Idaho Load (July) & Estimated Impact of Schedule 72



Technical challenges

During the 2005 irrigation season, field technicians experienced an unusually high frequency of timer malfunctions. Upon making this discovery a conference call was made between the Load Control Management Team, field technicians, Consolidated Electrical Distributors (the distributors through which the timers are purchased) and the clock manufacturer Grasslin (U.S. headquarters in NJ)[6]. Grasslin's U.S. Engineering group requested and was provided with a half of dozen of the failed units. At first, their evaluation was inconclusive other than that the batteries had clearly failed. At the time of the preparation of the drafting of the 2005 year-end report their European counterparts were similarly unable to precisely pin-point the cause of battery failure.

Additional analysis was conducted during the early winter. Around the first of the New Year the principal board designer was contacted and a root-cause analysis prepared. It turned out that the cause of the failure was a miscalculation on the circuit board used in the timer as to the amount of Amperes drawn on the battery. That is, the failed board design exceeded the (Amp-hour (Ah) rating) of the battery itself. Changes in the board design were made to correct the problem and no cost replacement units provided to Rocky Mountain Power for the 2006 *Program* season.

[6] Grasslin is a European timer manufacturer who was acquired by GE in 2002.

With new equipment, but without knowledge of the status of each of the field installed units, a decision was made to visit and assess each of the installed timers. Accordingly, *Program* technicians were instructed to test and replace, where necessary, each unit. With (1) more than 1,300 individual timers, (2) an uncertain and sporadic delivery date of the re-designed boards, (3) a dynamic *Program* participation customer base, (4) field technician scheduling / optimization, (5) weather vagaries and (6) only a limited installation window a re-drafting of field logistics and database modifications were required to meet the scheduled *Program* start date. Accordingly, some additional *Program* costs were incurred in juggling the logistics. However, it turns out that through the cooperation of end-use customers, committed field installers, a database administrator and the Company's Irrigation Hotline management / staff, total *Program* costs ended up being within anticipated 2006 budgets.

Measurement & Verification (M&V) processes

Consistent with the previous three irrigation seasons, field technicians prepared random, unannounced site visits for the purpose of ensuring the integrity of timer performance and the absence of fraud. Five timer and timer-related parameters ((1) tape seal, (2) meter lock, (3) battery, (4) clock calendar and (5) pump panel) were considered in the evaluation. M&V technicians were also asked to confirm the presence of PacifiCorp Site ID stickers for inventory purposes. Where it is suspected there were variances in any one or multiple above-defined components field technicians were required to indicate said variances in the database and to the Irrigation Load Control Management Team for adjudication. The results of the 2006 M&V activities are indicated in Table Eleven. In addition, there was one site reported to the Irrigation Load Control Management Team for adjudication but in this instance, evidence pointed to a field installation error, not end-use customer fraud.

Table Eleven
Results of the 2006 Measurement & Verification

QA Parameter	Ct. of Failures	Ct. of Units Inspected	Percent Failure
SiteID Sticker	41	144	28.50%
Tape Seal	6	144	4.20%
Pump Panel	5	144	3.50%
Meter Lock	1	144	0.70%
Clock Calendar	1	144	0.70%
Battery	0	144	0.00%

Crop type analysis

As part of the 2005 year-end report the Idaho Commission requested that the Company prepare analysis of avoided loads by crop type for the 2006 season. This analysis is somewhat problematic as a majority of field installations occur in January, February and March prior to when a grower has made a final decision on crops and prior to planting. Nevertheless, field technicians either inquired of the grower as to crop type or could identify the emerging crop himself (in the case of late-in-season installs). *Table Twelve: Known Site Estimation of Crop Type x Site &*

Avoided kW presents the results of these field data gathering efforts[7]. The avoided kW values were calculated by taking the full summer (1 June through 15 September) average for each of the identified sites and summing those avoided kW values by crop type.

Table Twelve
Known Sites Estimation of Crop Type x Site & Avoided kW

Crop Type	No. of Sites	Tot. Avg. kW
grain	439	52,363.5
hay	378	38,442.3
spuds	186	24,400.5
pasture	82	1,992.5
grass	40	1,273.2
corn	12	3,024.8
golf courses	4	124.7
sod	3	419.5
trees	3	76.1
canal	2	366.4
grain/potatoes	2	257.7
recharge	1	13.8
potatoes/corn	1	292.3
Totals	1,153	123,047.3

Despite being estimates, these data indicate that *Program* participation is largely limited to 'field' crops. 'Row' crops, particularly potatoes have not and do not participate in the Schedule 72 initiative. Moreover, the data clearly illustrates an opportunity to grow *Program* participation among potato growers. Additional consideration of this finding is further discussed in the *Program Enhancements Under Consideration* section.

Table Thirteen: 2006 Program Participant Estimation of Crop Type x Site & Avoided kW presents field installer estimates of only 2006 *Program* participant crop types. Again, these are estimates and the same constraints exist with these data as referenced with Table Twelve. Accordingly, attempts to synch-up avoided MW as reported in Table Twelve to reported *Program* totals should be avoided.

[7] Note: these estimates represent information about ALL known sites in the PacifiCorp service territory whether the site was participating in the 2006 initiative or not.

Table Thirteen

2006 *Program* Participant Estimation of Crop Type x Site & Avoided kW

Crop Type	No. of Sites	Tot. Avg. kW
grain	360	44,309.2
hay	315	31,912.7
spuds	93	13,131.1
pasture	72	1,612.5
grass	30	1,065.5
corn	9	2,268.5
golf courses	3	122.2
sod	3	419.5
trees	3	76.1
canal	2	366.4
grain/potatoes	2	257.7
potatoes/corn	1	292.3
recharge	1	13.8
Totals	894.0	95,847.5

Table Fourteen: 2006 Program Participant Estimation of Crop Acreage x Crop Type presents field installer estimates of only 2006 *Program* participant crop types x acreage. Here again, these values represent estimates and the same constraints exist with these data as referenced with Table Twelve and Thirteen.

Table Fourteen

2006 *Program* Participant Estimation of Crop Acreage x Crop Type

Crop Type	Total Acres
grain	64,026
hay	50,623
spuds	13,970
pasture	3,644
corn	2,460
grass	1,534
grain/potatoes	1,200
sod	560
golf courses	300
potatoes/corn	300
trees	121
Totals	138,737

***Program* enhancements under consideration**

Over the course of the three years that Schedule 72 (*Irrigation Load Control*) has been available to Rocky Mountain Power's Schedule 10 (APS) customers, the Irrigation Management Team has attempted to consider and implement operational changes to (1) enhance delivery, (2) improve efficiencies, (3) provide for greater data integrity / accuracy and (4) grow customer participation. The 2006 irrigation season is no different. In 2006 the Irrigation Management Team piloted a new control technology. 25 new control technology units were field tested at 14 customer sites. If, it was reasoned, the results of the field test proved successful then additional changes could be considered to one or more of the aforementioned objectives to further improve *Program* performance. Moreover, a successful trial could mean the technology would be considered for implementation in the 2007 irrigation season. The information that follows is a summary of the pilot background, objectives, customer assessments and anticipated benefits.

Background

Previous year failures with the electronic timers has created and/or contributed to (1) increased field maintenance costs, (2) customer dissatisfaction / frustration, (3) lower than expected *Program* participation, and (4) administrative overhead / burden. Beginning in the late fall 2005 and throughout the winter, 2006 the Irrigation Management Team began to identify and investigate alternative control technologies. Two technologies were bench tested and one (M2M Communications, Boise, ID) was selected for further consideration and piloting during the 2006 irrigation season.

Throughout the 2006 irrigation season 25 sites (14 customers) participated in testing the fully duplexed (cellular / satellite) M2M pump/pivot control technology. M2M provides the underlying remote control equipment to *Valley Irrigation* the world's most popular and largest agricultural pivot manufacturer. This particular product line (remote pivot control) has been available for five years and, according to Valley, is one of the more popular options to their base equipment. Moreover, the equipment's durability has received a favorable endorsement as a function of little / no reports of failure / malfunction during the five years it has been in the field[8]. The version of the control equipment tested in 2006 was based upon and nearly identical to that used by *Valley Irrigation*.

Underlying objectives

It was anticipated that the M2M technology would lower the recursive field costs and provide a platform for additional agri-business offerings. These new offerings would create operational efficiencies and improve performance reliability. By so doing, it was hypothesized that a value proposition could be struck that would address agri-business practices important to growers thereby capturing additional participation. Driving much of the thinking behind the pilot was a bias towards potato growers and the need to capture their participation if the *Program* were to increase in volume. Moreover, the offering could move the Load Control *Program* beyond a simple exchange of participation credit for shifted load. That is, growers could be provided with additional dispatch-options for growers. This approach would also eliminate the stranded equipment assets currently incurred as a function of crop rotations. Ultimately, and over time, the M2M equipment would replace the current solid state Grasslin timers.

[8] As reported by equipment distributors, customers and Valley's own internal statistics.

Equipment benefits / costs

An additional benefit of the M2M equipment is the elimination of M&V as the new control technology provides an authoritative log of pump activity. But perhaps most important is the benefit of being able to remotely query the unit and test operational effectiveness. The new equipment is solid state design so there are no moving parts or battery to keep date/time in synch as all intelligence has been migrated to the server to which the field unit communicates. The grower has improved and increased flexibility in managing equipment to meet their agri-business requirements as all commands can be managed either through the Internet or via standard telephony (cellular or traditional landline). Older RF controllers used in the past often ended up being disconnected from the system due to breaking of antennas or coffee can shields. It is not anticipated that the M2M technology will experience this sort of either active or passive sabotage because the grower now, operating his irrigation equipment through the M2M technology, has a 'vested interest' (both operational and economic) in the equipment's effective operation.

The down-side of this technology is (1) capital and (2) recursive air time communication (satellite / cellular) charges. Recursive air time communication costs only occur during the season and their impact is ≅ $7 per site per month. The cost of the unit itself is more than twice the standard Grasslin timer currently in use. However, this is somewhat misleading. Evaluation of current and past budgets suggests that recursive field costs incurred by one-way technologies (or in the case of the Idaho program Grasslin timers) have added substantial to the overall base costs for these technologies. These un-anticipated costs have had a negative impact on *Program* performance. Moreover, timer failure has had a negative effect on customer service. Based on revised proforma calculations taking into consideration the use of the M2M equipment, life-cycle and maintenance costs, the M2M equipment would be more cost effective than the current Grasslin timer technology. For example, current Grasslin timer technology costs ≅ $315 per site[9] and due to the lack of reliability of the timer the Irrigation Management Team has determined that each site configured with a timer MUST be visited each year. This decision has been made to maintain appropriate and reasonable levels of customer service and to ensure grower participation in the Program does not further erode. Factoring in that ≅30% of the participating sites require two or more timers + an annual site visit + troubleshooting at .05% of the total population the M2M equipment at ≅$570 per site break even is less than one control season.

Pilot results

With the exception of a single unit which appeared to fail as a function of installation error the M2M equipment operated according to design specifications. The Irrigation Management Team received a number of anecdotal comments from customers indicating their surprise and pleasure in being notified when the status of the pump changed as a function of a power interruption or lightning.

[9] Note that ≅ 30% of the sites require two or more timers. This situation occurs when a grower does not have either a pressure switch or a low voltage control connection between the pump and the pivot. In these instances the cost to control that site is roughly doubled or $600 per site.

Modeling

Currently the Company's Commercial & Trading (C&T) organization is performing cost effectiveness modeling assuming the installation and use of the proposed technology as a fully dispatchable solution. As of the preparation of this report, the results of these analyses are not yet available. However, when these data become available and if it is determined that a significant and measured change to the *Credit Rider Initiative* could be implemented, the Company will bring its recommendations to the Commission for consideration.