ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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UTILITIES COMMISSION

201 South Main, Suite 2300
Salt Lake City, Utah 84111

December 19, 2007

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

Attention: Jean D. Jewell
Commission Secretary

Re: Irrigation Load Control 2007 Report Including Dispatch Pilot Program
Case No. PAC-E-06-12

Rocky Mountain Power, a division of PacifiCorp, hereby submits for filing its report detailing the operation of the Irrigation Load Control Credit Rider Program, including the operational results of the 2007 dispatchable pilot program. This report is provided in compliance with Order No. 30243 issued in the above referenced case.

The Company recommends continuing the dispatchable program as a demand side management program offering in its Idaho service territory. An agreement with regards to continued program operation and the level of incentives was reached with the Idaho Irrigation Pumpers Association as part of the Company's 2007 general rate case and was submitted to the Commission for approval in Case No. PAC-E-07-05. Revised tariffs will be submitted in compliance with the Commission's order in that case once it is issued.

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

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

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

By fax: (503) 813-6060

Any informal inquiries may also be directed to Brian Dickman, Idaho Regulatory Affairs Manager, at 801-220-4975.

Sincerely,

Jeffrey K. Larsen /DD

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Schedule 72 & 72A Idaho Irrigation Load Control *Programs*

2007 Credit Rider Initiative Final Report

18 December 2007

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Report Organization

Idaho Public Utilities Commission Order No. 29209 and Order No. 29416 in Case No. PAC-E-03-14 requires Rocky Mountain Power (the Company), a division of PacifiCorp, prepare an annual report on the *Idaho Irrigation Load Control Program (Program)*. As approved by the Commission in Order No. 30243, Rocky Mountain Power initiated a dispatchable irrigation pilot program (Schedule 72A) evaluating the efficacy of a 2-way control technology unique to the irrigation industry. In addition to the standard analysis on Schedule 72, this report will include a review of Schedule 72A as required by the Commission order. The Schedule 72A assessment will follow the standard report. Finally, summary statistics from both Schedule 72 and Schedule 72A will be combined and presented.

Background

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*

2007 Schedule 72 (Scheduled Forward) Results

Table One details eligible 2007 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, 2005 and 2006 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 2007, 14.8% of total available sites and 20.0% of the total available customers participated in the *Program*. There are zero customers NOT eligible to participate in 2007 (requirement #4).

[1] Data are reported as of 30 September 2007. This notation is important as *Program* participants may change throughout the season 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.

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
2007 Actual Participants	681	405
Eligible 2007 Counts	4,596	2,014
Customers NOT eligible to participate 2007	N/A	0

Note: based on 30 September 2007 data sets

The monthly participation credit amounts issued to 2007 *Program* participants are presented in Table Two (requirement #5). Total *Program* participation credits ($684,201.09) represent a 26.1% decrease (or -$240,652.35) over 2006 credits. This decrease in credits occurred despite the addition of $450,000 (denoted 'Supplemental Credit') divided among all 2007 Program participants. The reason for this decrease is because a significant count of growers elected to participate in the Dispatchable (Schedule 72A) pilot program. 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, 2006 and 2007 *Program* years.

Further, it should be noted that the 2007 *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.

Table Two
2007 Scheduled Forward Participation Credits x Month

	June	July	August	September
Standard Credits	$110,951.25	$181,494.39	$165,409.32	$38,782.30
kW Under Contract	37,501.29	51,506.00	49,664.00	40,491.80
Total Season Supplemental Credits	$188,287.72			
Total Credits (Standard + Supplemental)	$684,924.98			

Table Three
2003–2007 Comparative Schedule 72 Participation Credits Issuance

Year	Total Participation Credits Issued
2003	$277,583.72
2004	$410,325.49
2005	$842,666.80
2006	$925,577.33
2007[2]	$684,924.98

Table Four provides information on 2007 *Program* costs (Note: Program costs for both Schedule Forward and Dispatchable initiatives are included in Table Four. Separate program costs used in determining cost-effectiveness are delineated in each of the 'Cost-effectiveness' sections of the report.). For years 2003, 2004, 2005 and 2006 *Program* costs are represented for comparative purposes.

During 2007 100% of sites that participated in the Scheduled Forward Program during 2006 were visited to inspect equipment and identify faulty timers[3]. This practice of visiting ALL participating sites was initiated in 2006 in response to the lack of control equipment reliability. This site inspection practice had a dramatic effect on customer service as there was less than eight customer service calls (or 1.17% of total timer-installed sites)[4] associated with equipment failures during 2007. For 2007 the more than doubling of costs for field expenses is due to (1) the $529k for new 2-way equipment and (2) field labor costs to remove timer units in advance of the installation of 2-way equipment and required for inventory balancing.

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

Cost Category	2003 Costs (April '03–Sept '03)	2004 Costs Oct '03–Sept '04	2005 Costs Oct '04–Sept '05
Administrative support	$9,613.43	$1,665.29	$851.56
Program evaluation	$2,135.43	$8,369.88	$1,820.00
Field / Equip / Db admin. expenses	$250,222.98	$239,807.03	$326,061.01
Participation credits	$277,583.72	$410,325.49	$842,666.80
Program management	$10,992.99	$55,036.29	$54,826.69
Reporting	$351.79	$1,940.00	$0.00
Total Program costs	$550,900.34	$717,143.98	$1,226,226.06

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

[2] Includes 'standard participation' credits + 'supplemental' credit for 2007 Scheduled Forward program participants only.
[3] The only program offered during 2006 was the Scheduled forward initiative
[4] If calculations were prepared on the total number of timers installed (not sites) the percent of failures would be even less (likely <1.0%).

Table Four (cont)
Comparative Load Control *Program* Costs 2006 & 2007

Cost Category	2006 Costs Oct '05–Sept '06	2007 Costs Oct '05–Sept '06
Administrative support	$194.60	$1,500.00
Program evaluation	$1,125.00	$2,268.75
Field / Equip / Db admin. expenses	$330,802.05	$747,664.85
Participation credits	$925,577.33	$1,752,930.47
Program management	$ 42,554.85	$ 80,144.00
Reporting	$0.00	$0.00
Total Program costs	$1,300,253.83	$2,584,508.07

Table Five provides avoided kW statistics and participation site counts for the Scheduled Forward initiative based on participation option. A couple of observations are noteworthy. First, and as reported in the 2006 year-end report, the three hour option was **not** a particularly popular offer. Growers reported that the inconvenience and associated labor of having to accommodate a three-hour interruption was not offset by the participation credit. Second, the six hour dispatch blocks were, by far, the most popular option, representing 88.1% of total *Program* site participation and 87.1% of total avoided kW.

Table Five
Program Impacts by Participation Option

Participation Option	Site Ct.	June Avoided kW	July Avoided kW	Aug. Avoided kW	Sept. Avoided kW
Option I m w 2-8	310	16,667.8	22,631.6	21,395.8	16,700.8
Option I t th 2-8	290	17,520.3	22,524.5	21,582.6	18,084.1
Option II m w 3-6	6	443.3	615.0	613.9	263.4
Option II m w 4-7	6	188.3	276.4	285.4	260.4
Option II t th 3-6	5	149.0	264.1	284.8	251.0
Option II t th 4-7	5	115.0	151.6	129.6	124.3
Option III m t w th 3-6	26	921.1	1,252.5	1,267.7	1,101.8
Option III m t w th 4-7	24	751.8	872.0	922.1	761.7
Option IV m 2-8	9	2,425.0	3,122.7	3,086.4	2,959.6
Totals	681	39,181.6	51,710.4	49,568.3	40,507.1

Note: data reported as of 30 September

Tables Six through Nine transpose the data presented in Table Five into hourly dispatch schedules by each of the four Schedule Forward dispatch days (Monday–Thursday). Each of the four subsequent tables indicates the avoided kW by month, control day (Monday–Thursday) and hour.

Table Six
2007 Avoided kW by Month, **Monday** Control Day & Hour

JUNE Monday 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	19,077.5	20,441.9	21,382.0	21,382.0	20,017.6	19,077.5

JULY Monday 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	25,731.0	27,598.5	28,746.9	28,746.9	26,879.4	25,731.0

AUGUST Monday 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	24,458.9	26,340.5	27,548.0	27,548.0	25,666.4	24,458.9

SEPTEMBER Monday 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	19,645.1	21,010.3	22,032.4	22,032.4	20,667.2	19,645.1

Table Seven
2007 Avoided kW by Month, **Tuesday** Control Day & Hour

JUNE Tuesday 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	17,520.3	18,590.4	19,457.2	19,457.2	18,387.1	17,520.3

JULY Tuesday 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	22,524.5	24,041.1	25,064.7	25,064.7	23,548.1	22,524.5

AUGUST Tuesday 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	21,582.6	23,135.1	24,186.8	24,186.8	22,634.3	21,582.6

SEPTEMBER Tuesday 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	18,084.1	19,436.9	20,322.9	20,322.9	18,970.1	18,084.1

Table Eight
2007 Avoided kW by Month, **Wednesday** Control Day & Hour

JUNE 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	16,652.5	18,016.9	18,957.0	18,957.0	17,592.6	16,652.5

JULY 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	22,608.3	24,475.8	25,624.2	25,624.2	23,756.7	22,608.3

AUGUST 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	21,372.5	23,254.1	24,461.6	24,461.6	22,580.0	21,372.5

SEPTEMBER 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	16,685.5	18,050.7	19,072.8	19,072.8	17,707.6	16,685.5

Table Nine
2007 Avoided kW by Month, **Thursday** Control Day & Hour

JUNE 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	17,520.3	18,590.4	19,457.2	19,457.2	18,387.1	17,520.3

JULY 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	22,524.5	24,041.1	25,064.7	25,064.7	23,548.1	22,524.5

AUGUST 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	21,582.6	23,135.1	24,186.8	24,186.8	22,634.3	21,582.6

SEPTEMBER 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	18,084.1	19,436.9	20,322.9	20,322.9	18,970.1	18,084.1

Cost-effectiveness analyses

Cost-effectiveness will be calculated for the following program components:

1. Schedule 72 (Scheduled Forward) only
2. Schedule 72A (Dispatchable) only
3. Schedule 72 and Schedule 72A (combined)

Results on each of the four standard utility industry tests–(1) Total Resource Cost (TRC); (2) Utility; (3) Ratepayer and (4) Participant will be provided for each of the three aforementioned program cases. The tests for Schedule 72 (Scheduled Forward program component) will be based upon the cost and avoided MW values as defined in Table Ten below[5]. The information below will describe the methodology and will be used in evaluating each of the subsequent program components.

Table Ten
2007 Benefit / Cost Categories & Values–Schedule 72

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$495.00	$/kW-yr avoided	$49.56
Program evaluation	$1,134.38		
Field / Equip / Db admin. expenses	$186,916.21		
Participation credits	$684,924.98		
Program management	$27,248.96		
Reporting	$0.00		
Total	$900,719.53		

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[6]. The benefits are based on the calculations as defined by the Company's Commercial & Trading organization[7]. Costs used in these calculations include administrative costs, contractor costs (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 is consistent with previous program year calculations) as a result of customers participating in the Program by the estimated value of avoided demand noted above. Again, this value is $49.56/kW-yr. This value is increased by 10% to account for the effect of line (T&D) losses, resulting in a value of $54.52/kW-yr used in the cost-effectiveness calculations.

[5] To the extent possible, certain cost categories have been allocated by the respective Schedule initiative
[6] Note that no discounting of costs or benefits was required in this analysis since all costs and benefits occurred in 2007.
[7] The methodology for determining avoided costs ($/kW-yr) are on file with the Company's Commercial & Trading organization (C&T).

Based on previous research that showed energy use is 'shifted' rather than 'avoided', lost revenues are not included as a cost and energy savings are not applicable as indicated above.

As shown in Table Eleven, the Scheduled Forward component of the program passes the TRC Test. The Scheduled Forward program also passes the Utility and Ratepayer Test. Since the participant incurs no costs the benefit/cost ratio would be infinite for the Participant Test. Accordingly, for the Participant Test the value is indicated as 'N/A' in Table Eleven.

Table Eleven
2007 Schedule 72 Cost-effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$1,351,008	$215,795	$1,135,214	6.26
Utility	$1,351,008	$900,720	$450,289	1.50
Ratepayer	$1,351,008	$900,720	$450,289	1.50
Participant	$684,925	$0.00	$684,925	N/A

Measurement & Verification (M&V) processes

Consistent with the previous four irrigation seasons, field technicians prepared random, unannounced site visits for the purpose of ensuring the integrity of timer performance and the absence of grower 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 a PacifiCorp Site ID sticker for inventory purposes. Where it is suspected there were variances in any one or multiple of the aforementioned evaluation elements 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 2007 M&V activities are indicated in Table Twelve. There were two sites reported to the Irrigation Load Control Management Team for adjudication. On both of these occasions the Irrigation Product Manager contacted the growers involved. With each incident the information clearly indicated no outward attempt to circumvent the control equipment or defraud Rocky Mountain Power. In both instances the center pivot was stopped during a control event at a position in the field requiring the grower to manually by-pass the equipment in order to move the pivot for the harvesting machinery too access that position in the field. Subsequently, the control equipment was corrected for proper dispatch sequencing. In both instances growers were advised that in future they should contact Rocky Mountain Power prior to manipulating the control equipment.

Table Twelve
Results of the 2007 Measurement & Verification

QA Parameter	Ct. of Failures	Ct. of Units Inspected	Percent Failure
SiteID Sticker	29	101	28.7%
Tape Seal	1	101	0.9%
Pump Panel	2	101	1.9%
Meter Lock	1	101	0.9%
Clock Calendar	0	111	0.0%
Battery	0	111	0.0%

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2007 *Schedule 72A (Dispatchable) Results*

In the fall of 2006, coincident with the year-end report and based on the results of a 25-unit pilot test of the prototype control technology, Rocky Mountain Power proposed and subsequently received permission to pursue a full-scale pilot test of a fully dispatchable solution for the 2007 irrigation season. The results of the Dispatchable program are described below.

Background

A total of 17 customers (448 sites) participated in the full-scale Dispatchable initiative using the proprietary (cellular / RF) M2M pump / pivot control technology. M2M provides the underlying remote control equipment to *Valley Irrigation* the world's largest agricultural pivot manufacturer. This particular product line (remote pivot control) has been available for five years. Rocky Mountain Power worked with M2M in the design, development and manufacturing of a wireless proprietary master / slave configuration such that a 1 to many pump / pivot configuration could provide independent control of irrigation sites[8]. This was viewed as a major step forward in providing an agri-business solution that would attract grower participation.

Prospective large-grower participants were contacted and originally notified of the pilot in late fall 2006. In the spring of 2007 these growers were again notified that the pilot had been approved by the Idaho Public Utilities Commission and asked if they would like to participate. Growers who indicated a preference for participation during the 2007 season were subsequently notified to disregard the standard notification mailing announcing the Idaho Irrigation Load Control program for 2007. Growers were also told that the Irrigation Management Team would work directly with them or their farm managers in preparing program participation application materials, site preparation / installation and training on equipment use.

Concurrent with the management of the grower interface, the Irrigation Management Team worked closely with M2M Communication in technology reviews and software development readying the technology for manufacturing and later field deployments.

The Irrigation Management Team also deployed field technicians to begin removal of the solid-state timers during the late winter and early spring period preparing the Dispatchable sites to receive the new 2-way control units. These parallel efforts (technology development, grower communications and site preparation) continued during the late winter / early spring period until M2M units began to ship.

In communicating with the growers about the Dispatchable program growers were apprised of the foundational components of the Dispatchable pilot including but not limited to the operating parameters described in the 'Tariff highlights' below.

[8] As with the timer technology it should be noted that a single irrigation site often required multiple 'slave' units in order to service a single site. That is, it is not uncommon for a single pump to be sized and connected to multiple pivots. The master/slave technology provided by M2M allows the user to independently operate the pump as well as each pivot site. With these configurations, however, separate field installations had to be completed on the pump as well as on each pivot.

Tariff highlights

The operational parameters of the approved tariff are bulleted below:

- Applicable: To qualifying customers served on Schedule 10 and who met the following participation criteria:
  - an aggregate minimum of 1MW (1,500 Hp) demand under their control (single account or multiple accounts) for either or both of July or August
  - an integrated pump / pivot irrigation system
  - a minimum pump size of 100 Hp
  - continuous access to the Internet from May 1 through September 15
- Grower Notification: grower would be notified on a day-prior and day-of the Dispatch Event
- Grower Opt-out: growers could, upon their discretion, opt-out of 2 'Dispatch Events' with no financial penalty. Growers could also opt-out of 3 additional 'Dispatch Events' but would incur a financial penalty described below in the 'Liquidated Damages' section.
- Liquidated Damages: Growers could 'opt-out' of up to a maximum of five Dispatch Events with the provision that any opt-outs beyond the first two the grower would have their credits reduced by the amount the Company would otherwise have to pay for power for the duration of the 'Dispatch Event'.
- Dispatch Conditions: The Company shall have the right to implement a Dispatch Event for participating customers according to the following criteria:
  - Available Dispatch Hours: 2:00 PM to 8:00 PM Mountain Daylight Savings Time (MDT)
  - Maximum Dispatch Hours: 65 hours per Irrigation Season
  - Dispatch Duration: Not more than three and one-half hours per Dispatch Event
  - Dispatch Event Frequency: limited to a single (1) Dispatch Event per day
  - Dispatch Days: Monday through Friday (inclusive)
  - Dispatch Day Exclusions: July 4 and July 24 and/or their respective designated weekday official holiday

Installation schedule

The design, manufacturing, and installation nuances related to the dispatchable units and the requirement to ensure 100% quality control of all hardware components meant installation was delayed such that not all units were fully installed by the start of the tariffed irrigation season (1 June). Nevertheless, a substantial number of units (271 units OR 41.6MW) were installed and readied prior to the initial Dispatch Event on 6 July. Subsequent installations and training of growers on equipment use meant that installations came on-line in series following installation, database and Internet control reading of all user interfaces and user training.

To manage this process and because there were a far greater number of installation considerations that needed to be taken into account, the Irrigation Management Team contacted a single grower who expressed interest in the technology and was willing to act as defacto 'guinea pigs' for technology introduction. This gesture on the part of this grower allowed the Irrigation Management Team to work through the many

technical and operational challenges the new technology presented. This meant that, instead of installing all 448 participating sites in parallel with multiple installation teams, the field effort would focus on getting the installation process, technology settings and database components correct with this single grower before moving on to parallel installations with subsequent growers.

In the end, this approach proved effective for two reasons. First, problems and technical challenges could be reasonably solved without unduly impacting all growers. The potential 'damage' (negative spin, grower discontent, and frustrations) was limited to a single grower rather than to the entire population of participating growers. Second, field costs were limited as field re-work was constrained to a specific count of sites and not all of the participating sites. This approach resulted in conserving field expenses. The following example may help to further clarify the field cost issue.

When field installations were begun, units were deployed with Operating System (OS) v 3.0. By the time the installation of all units was complete OS v 9.0 was being installed. Having to re-install all 448 sites (and, in many cases, their 'slave' counterparts) with each new release of the OS (seven additional site visits to each site) would have unduly impacted field operating budgets and further delayed installation of units to all growers. As it turned out, the Irrigation Management Team was able to eliminate a certain amount of redundant field work and contain grower discontent by adopting a serial approach to installation rather than a parallel approach. The trade-off, of course, was that participating loads came on-line in chunks throughout July (see Table Thirteen) with all participating loads available for the August through September dispatch period.

Table Thirteen
Cumulative Participating Loads Available for Dispatch x Dispatch Event

Count of Dispatch Events	Date	Duration (hrs)	Cumulative Duration (hrs.)	Cumulative Participating Loads (kW.)
1	6-Jul-07	3.5	3.5	41,392.6
2	12-Jul-07	3.0	6.5	41,392.6
3	16-Jul-07	3.5	10.0	52,760.5
4	19-Jul-07	3.0	13.0	55,000.5
5	23-Jul-07	3.0	16.0	55,000.5
6	26-Jul-07	3.0	19.0	67,891.1
7	31-Jul-07	3.0	22.0	69,803.8
8	3-Aug-07	3.0	25.0	76,397.1
9	8-Aug-07	3.0	28.0	76,397.1
10	10-Aug-07	3.0	31.0	76,397.1
11	13-Aug-07	3.0	34.0	76,397.1
12	15-Aug-07	3.0	37.0	76,397.1
13	17-Aug-07	3.0	40.0	76,397.1

Table Fourteen indicates by participating grower number[9] the 17 growers that participated in the pilot Dispatchable initiative, their participating loads and the percent each of those loads represent of the total participating in the Dispatchable component of the irrigation load control initiative.

[9] Grower names have been replaced by grower # to maintain the anonymity of the growers and their irrigation loads.

Table Fourteen

2007 Participating Loads x Grower and the Percent Each Load Represents of the Total

Grower	Participating Loads (kW)	% of Dispatchable Total
Grower 1	893.7	1.2%
Grower 2	3,645.9	4.8%
Grower 3	3,067.8	4.0%
Grower 4	823.6	1.1%
Grower 5	1,416.4	1.9%
Grower 6	2,539.6	3.3%
Grower 7	1,848.1	2.4%
Grower 8	12,326.2	16.1%
Grower 9	13,669.0	17.9%
Grower 10	11,367.9	14.9%
Grower 11	5,625.9	7.4%
Grower 12	1,912.7	2.5%
Grower 13	2,679.4	3.5%
Grower 14	2,316.0	3.0%
Grower 15	1,209.7	1.6%
Grower 16	4,461.9	5.8%
Grower 17	6,593.3	8.6%
Total	76,397.1	100.0%

Customer Credits

All dispatch customers were issued both standard tariff credits of $11.19/kW avoided and supplemental credits. Supplemental credits were calculated based upon the portion of load a grower's particular pump site represented of the total (both Scheduled Forward and Dispatchable) under control for the 2007 irrigation season. Credits by type and total credits are reflected in Table Fifteen below.

Table Fifteen

2007 Dispatchable Participation Standard & Supplemental Credits

	Credit Type	
	Standard	Supplemental
Credit Amount	$806,293.21	$261,712.28
Total Dispatchable Credits		$1,068,005.49

Customer Opt-Outs

Schedule 72A permits growers to 'opt-out' of two Dispatch Events with no financial penalty. Growers are also permitted to opt out of three additional Dispatch Events but would be charged the price Rocky Mountain Power would otherwise have to pay for power during that dispatch period. For the 2007 pilot season growers were NOT assessed fees (credit discounts) for opt-outs beyond the allowed two. There were two reasons growers were NOT assessed the fees.

First, as an entirely new technology both software and hardware needed to be stress-tested. In so doing the Irrigation Management Team coordinated with the grower and their farm managers in executing and requiring opt-outs during each of the 13 Dispatch Events in order to test both hardware and software system components.

Second, was the issue of technology usability and grower training. Technology usability was and remains the single biggest obstacle to technology adoption. The Irrigation Management Team understood that for the Dispatchable initiative to be successful growers and their farm managers would have to change operational habits and practices. Fundamentally, that meant controlling pump / pivot sites either through their cell phone or the Internet. This was not a trivial consideration. Accordingly, much effort was taken to train growers / farm managers on the new technology.

The Irrigation Management Team urged practice use of the equipment, including opting-out of Dispatch Events even though the grower would have otherwise participated in the Dispatch Event. The decision was made and the objective adopted to get growers / farm managers comfortable with the technology and its operation. Bottom line: Schedule 72A was a pilot and the Irrigation Management Team treated it as such and encouraged growers / farm managers to do likewise. Nevertheless, statistics were gathered on the count of opt-outs and load NOT avoided by Dispatch Event. These data are presented in Table Sixteen. (Note: of the first three Dispatch Events (July 6, 12, 16) approximately 91% of the opt-out counts originated from a single grower. Again, on July 26 and 31 more than 80% of the opt-outs originated from that same grower.)

Table Sixteen

2007 *Dispatch Event Parameters, Count of Opt-Outs & Loads Not Avoided*

Count of Dispatch Events	Date	Duration (hrs)	Cumulative Participating Loads (kW.)	Ct. of Opt-Outs	Load NOT Avoided (kW)	Net Load Avoided
1	6-Jul-07	3.5	41,392.6	51	8,087.5	33,305.1
2	12-Jul-07	3.0	41,392.6	59	9,187.5	32,205.1
3	16-Jul-07	3.5	52,760.5	71	8,437.5	44,323.0
4	19-Jul-07	3.0	55,000.5	6	1,800.0	53,200.5
5	23-Jul-07	3.0	55,000.5	0	0.0	55,000.5
6	26-Jul-07	3.0	67,891.1	16	1,800.0	66,091.1
7	31-Jul-07	3.0	69,803.8	20	3,110.5	66,693.3
8	3-Aug-07	3.0	76,397.1	8	900.0	75,497.1
9	8-Aug-07	3.0	76,397.1	1	600.0	75,797.1
10	10-Aug-07	3.0	76,397.1	0	0.0	76,397.1
11	13-Aug-07	3.0	76,397.1	1	100.0	76,297.1
12	15-Aug-07	3.0	76,397.1	0	0.0	76,397.1
13	17-Aug-07	3.0	76,397.1	11	1,125.0	75,272.1

2007 Dispatch Events

The avoided demand by dispatch hour associated with each of the Dispatch Events is presented in Table Seventeen. The values in this table represent dispatchable loads only. A zero (0) appears in several of the hourly cells (most notably the 2:00p–4:00p block). This is due to the fact that the dispatchable initiative was only exercised for either a 3.0 or 3.5 hour block (4:00p-7:00p / 7:30p). The reader should also be aware that on July 6 and, again, on July 16 the Dispatchable option was exercised for 3.5 hours. To accommodate the ½ hour during the 7:00p-7:59p period the Dispatchable load was reduced by 50%. In reality the full load was realized for the first 30-minutes of this dispatch hour and zero load during the second half of the 7:00p-7:59p period. While not perfect, taking 50% of the total load was the most expeditious way to represent these data in Table Seventeen without using ½ hour increment categories. Table Seventeen averages the loads (weighing each 'Dispatch Event' equally) by hour for each of the 13 'Dispatch Events'. Finally, it should be noted that there were NO (zero) instances reported where, once the technology was installed tested and operational on a stable operating system, the technology failed to respond to a Dispatch Event.

Table Seventeen

2007 *Dispatch Events x Dispatch Hour & Associated Parameters*

			Dispatch 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
Ct. of Dispatch Event	Date	Day-of-Week	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW
1	6-Jul-07	Friday	0	0	41,392.6	41,392.6	41,392.6	20,811.8
2	12-Jul-07	Thursday	0	0	41,392.6	41,392.6	41,392.6	0
3	16-Jul-07	Monday	0	0	52,760.5	52,760.5	52,760.5	26,495.8
4	19-Jul-07	Thursday	0	0	55,000.5	55,000.5	55,000.5	0
5	23-Jul-07	Monday	0	0	55,000.5	55,000.5	55,000.5	0
6	26-Jul-07	Thursday	0	0	67,891.1	67,891.1	67,891.1	0
7	31-Jul-07	Tuesday	0	0	69,803.8	69,803.8	69,803.8	0
8	3-Aug-07	Friday	0	0	76,397.1	76,397.1	76,397.1	0
9	8-Aug-07	Wednesday	0	0	76,397.1	76,397.1	76,397.1	0
10	10-Aug-07	Friday	0	0	76,397.1	76,397.1	76,397.1	0
11	13-Aug-07	Monday	0	0	76,397.1	76,397.1	76,397.1	0
12	15-Aug-07	Wednesday	0	0	76,397.1	76,397.1	76,397.1	0
13	17-Aug-07	Friday	0	0	76,397.1	76,397.1	76,397.1	0
Average 'Dispatch Event' Avoided kW x hr.			0	0	64,740.3	64,740.3	64,740.3	23,653.8[10]

Note: data presented in this table ignore all Company- and grower-initiated opt-outs (see Table Sixteen)

[10] The mean for the 7:00-7:59p hour was calculated ignoring the zeros (0) in the eleven dispatch events.

Customer Feedback

The Company has, based on historical precedence, meteorological considerations and other class 1 initiatives, determined there would likely be 40 hours or 0.5% of the available annual hours a class 1 resource (such as irrigation load control) would likely operate[11]. The Irrigation Management Team wanted to provide growers with a realistic feel for the number and duration of dispatches so they could provide reasonable post-season feedback and could make a realistic assessment for participation in subsequent irrigation seasons. The Irrigation Management Team was also interested in this feedback so the appropriate adjustments, if any, could be made to improve the program offering.

As a pilot, and in addition to the ad hoc feedback received from growers / farm managers throughout the irrigation load control season, it was important to collect grower data relative to the Dispatchable initiative. Moreover, gathering grower feedback was required in the Commission order approving Schedule 72A. It was hoped that information gained from the questionnaire and associated discussion would assist in making specific changes that would (1) improve operations, (2) enhance the value proposition to both the grower and to Rocky Mountain Power, and (3) improve cost-effectiveness. Accordingly, a brief questionnaire (see Attachment One) was developed and used in a post-season interview with growers. In addition to the questionnaire a follow-up information gathering interview was held with each of the growers / farm managers to gain additional insights / observations as to the Dispatchable initiative's strengths and weaknesses. The six broad categories investigated by the questionnaire and reviewed in discussion are listed below.

1. Program introduction / terms and conditions
2. Selecting and scheduling site installations
3. Field installation activities / processes
4. 'Dispatch Event' operations
5. Training
6. M2M control equipment

Results from the questionnaire / interview with growers sort themselves into nine categories. A succinct description along with representative grower comments related to each of the categories follows.

1. The Company did a relatively good job informally communicating with growers as to the value proposition, tariff parameters and technology operations. Growers particularly appreciated the local presence of well known field technicians in whom they had confidence and trust to accurately and correctly represent the technology and operational considerations. The Company's local, well-known and trusted Customer and Community Management Representative [Bob Smead] was also cited by growers as having made program components understandable.
2. Growers were not as complementary when it came to keeping them (growers) abreast of development efforts. Until technical issues were largely resolved, the Irrigation Management Team allowed attentions to focus nearly exclusively on problem solving and gave little consideration to growers waiting in the wings for implementation on their farm(s). Communications to the large grower population was lacking.

[11] The 40-hours of dispatch is consistent with what other electric utilities report / anticipate based on requirements for peak avoidance.

3. While training efforts were ranked positively, nearly all growers offered a number of recommendations to improve training / technology implementation. Grower criticisms were instructive in assisting the Irrigation Management Team in making adjustments to the irrigation initiative. The nature of the criticisms (some of which are indicated below) suggest a partnership approach between growers and the Company.

   Improve the pump site naming / identification and how the software works...also need better / more explanation as to why certain sites are not applicable for participation.

   Need to do a better job of visiting with growers prior to the install and explaining operations and issues and how they impact the system.

   The information for managing slave / masters could and should be made more clear.

   On the website it would be helpful to be able to use the back key...also the website times-out too quickly need to lengthen this capability.

   The website need to be explained better or made to be more intuitive so it can stand alone without so much training / rehearsal.

   Naming conventions don't work for when you are just managing pumps vs. pumps and pivots...not being able to independently manage these units and name them accordingly makes the system awkward.

   Training, particularly for when you're training just for surface water folks, need improvement.

   We will need training again next year to know what we need to do and how to operate the equipment.

   Perhaps we ought to do both group training and individual (1:1) training, that way we can cover general stuff and take advantage of general information and then provide specifics.

4. Growers were somewhat irritated as to the delay in program implementation. These delays were viewed as being organizational and not technology-driven. There was a universally simple and clear message:

   Make sure the Company does enough in advance so that there is sufficient time to implement the program

5. The 'opt-out' option was enormously important to the Dispatchable value proposition. Without this option growers would have simply elected to not participate in the initiative.

   The 'opt-out' stuff was important to making the program work...single most important piece.

   Flexibility [opt-out] is what makes the whole deal work. Without this option this program is dead.

   Options [opt-outs] are key!

   More options is good...

   Opt-outs are the key.

   Key is to have opt-outs...that is what makes the program work.

6. The acceptance of the M2M control unit would take time for farm managers to get their arms around and get comfortable with. This finding was corroborated with data from Valmont Industries (Valley Irrigation) who indicated that it typically takes growers 3 seasons or more to become

completely familiar with the technology and confident it its reliability. Nevertheless growers feel it is a worthwhile transition and investment in time.

The farm managers learned how to use equipment but will have to re-learn next year.

We still have a way to go before all farm managers feel comfortable (probably 3-years for some of the farm managers) with the new equipment. But we will get there and in the end it will help the power company and help us with credits.

7. Growers valued and appreciated being able to solve problems with local resources. In the end, managing irrigation pumps / chemical pump tanks and pivots via the existing control panels and bolt-on utility equipment requires highly specialized knowledge. Growers do not allow anybody to drive onto their property and work on equipment which can often impact >$300,000 in potential revenue on a single pivot. Moreover, there are real threats of biological infestations that can be introduced to the acreage if vehicles and equipment are not properly cared for, attended to or if those doing the work do not have knowledge of agri-business operations.

   When you just throw program at us and say 'OK there it is' than it don't work...the people you have working on it [load control program] makes the whole deal work. If Brad, Andrew or Ty would have ignored the problems then we would have had a different result.

   Yeah, there were some glitches...but want local resources...don't want somebody in Chicago answering the phone or telling us what to do without really meaning it...this actually worked and your local people made it work...didn't hurt yield or quality either.

   The irrigation team got it working...you guys worked to get the farm managers to make it work.

8. Growers made a number of recommendations to improve control technology operations and program viability. It should be important to note that virtually 100% of the changes are software initiated adjustments and not changes to the fundamental underlying hardware. Among other items growers recommended the following:
   - Use text messaging for communicating status change conditions...the robotic voice is difficult to understand. Also, provide text messaging in Spanish.
   - Further shorten the call sequence to execute a particular command. Provide a sequence of code numbers without having to listen to the voice prompts...put this on the 'cheat sheets' provided to the growers.
   - Provide the user with the capability to view units grouped as well as ungrouped for the office staff.
   - Provide exception reporting and not simply status change reporting.
   - Want feedback when you opt-out. Growers need a little bit more of a road map such as pop-up screen saying "you are opting out, please confirm".
   - The status summary screen is not entirely clear on what is going on in the field.
9. Operating parameters appear to be an acceptable risk. That is, the three hour dispatch event was seen as virtually no different as a potential four hour Dispatch Event. Moreover, it was reported that a total of 50 hours seemed workable to growers so long as it got past the period when the canopy had grown over.

Cost-effectiveness analyses

Cost-effectiveness calculations were prepared for each of the four standard utility industry tests in the manner consistent with that described above for the Schedule 72 portion of this program. Benefits and costs for Schedule 72A (Dispatchable option) upon which calculations are prepared are presented in Table Eighteen below[12].

Table Eighteen
2007 Benefit / Cost Categories & Values–Schedule 72A

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$1,005.00	$/kW-yr avoided	$49.56
Program evaluation	$1,134.38		
Field / Equip / Db admin. expenses	$560,748.64		
Participation credits	$1,068,005.49		
Program management	$52,895.04		
Reporting	$0.00		
Total	$1,683,788.55		

As shown in Table Nineteen, the Schedule 72A passes the TRC, Utility and Ratepayer Tests. The Program also passes the Participant Test. However, since the participant incurs no costs the benefit/cost ratio would be infinite. Accordingly for the Participant Test the value is indicated as 'N/A' in the Benefit/Cost Ratio column.

Table Nineteen
2007 Cost-effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$3,856,470	$615,783	$3,240,687	6.26
Utility	$3,856,470	$1,683,789	$2,172,681	2.29
Ratepayer	$3,856,470	$1,683,789	$2,172,681	2.29
Participant	$1,068,005	$0.00	$1,068,005	N/A

[12] Again, to the extent possible, costs have been allocated by the respective Schedule initiative

2007 Schedule 72 & Schedule 72A Results

This section of the report provides a brief quantitative summary of the two combined initiatives–Schedule 72 (Scheduled Forward) and Schedule 72A (Dispatchable). Only minimum narrative will be provided as the majority of the rationale behind these data has already been provided.

Avoided demand

The avoided demand by dispatch hour associated with each of the Dispatch Events is presented in Table Twenty. The values in this table are additive. That is, they represent the combination of Scheduled Forward loads plus Dispatchable loads. Two important facts need to be taken into consideration in evaluating these data. First, a zero (0) appears in several cells. This is due to the fact that the Scheduled Forward initiative operates Monday thru Thursday inclusive. When the Dispatchable initiative was exercised on Friday the only avoided demand is that associated with Dispatchable loads. Second, on July 6th and, again, on July 16th the Dispatchable option was exercised for 3.5 hours. To accommodate the ½ hour during the 7:00p-7:59p period the Dispatchable load was reduced by 50%. In reality the full load was realized for the first 30-minutes of this dispatch hour and zero load during the second half of the 7:00p-7:59p period. While not perfect, taking 50% of the total load was the most expeditious way to represent these data. Finally, the table calculates the average (mean) as well as a median for each of the hourly loads per 'Dispatch Event'.

Table Twenty

2007 *Dispatch Events & Associated Parameters*

			Dispatch 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
Ct. of Dispatch Event	date	Name	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW	Tot. Avoided kW
1	6-Jul-07	Friday	0.0	0.0	41,392.6	41,392.6	41,392.6	20,696.3
2	12-Jul-07	Thursday	22,524.5	24,041.1	66,457.3	66,457.3	64,940.7	22,524.5
3	16-Jul-07	Monday	25,106.0	26,973.5	80,882.4	80,882.4	79,014.9	51,486.3
4	19-Jul-07	Thursday	22,524.5	24,041.1	80,065.2	80,065.2	78,548.6	22,524.5
5	23-Jul-07	Monday	25,106.0	26,973.5	83,122.4	83,122.4	81,254.9	25,106.0
6	26-Jul-07	Thursday	22,524.5	24,041.1	92,955.8	92,955.8	91,439.2	22,524.5
7	31-Jul-07	Tuesday	22,524.5	24,041.1	94,868.5	94,868.5	93,351.9	22,524.5
8	3-Aug-07	Friday	0.0	0.0	76,397.1	76,397.1	76,397.1	0.0
9	8-Aug-07	Wednesday	20,747.5	22,629.1	100,233.7	100,233.7	98,352.1	20,747.5
10	10-Aug-07	Friday	0.0	0.0	76,397.1	76,397.1	76,397.1	0.0
11	13-Aug-07	Monday	23,833.9	25,715.5	103,320.1	103,320.1	101,438.5	23,833.9
12	15-Aug-07	Wednesday	20,747.5	22,629.1	100,233.7	100,233.7	98,352.1	20,747.5
13	17-Aug-07	Friday	0.0	0.0	76,397.1	76,397.1	76,397.1	0.0
Mean 'Dispatch Event' Avoided kW x hr.			15,818.4	17,006.5	82,517.2	82,517.2	81,329.0	19,439.7
Median[13] 'Dispatch Event' Avd. kW x hr.			22,524.5	24,041.1	80,882.4	80,882.4	79,014.9	22,524.5

[13] Note: Where there are outlier values median values should be used as opposed to mean (average) values to more correctly reflect the avoided kW. Mean values skew data as they are unduly impacted by spuriously high (103MW) and low (zero) values.

Crop type analysis

Consistent with the 2006 report an analysis was prepared of avoided loads by crop type for the 2007 season. As mentioned in the 2006 year-end report 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 Twenty-One: 2007 Program Participation by Crop Type / Application x Site Count & Average Avoided kW* presents the results of these field data gathering efforts[14]. 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 / application.

Table Twenty-One

2007 Program Participation by Crop Type / Application x Site Count & Average Avoided kW

Crop Type / Application	Count of Sites	Total Avg. kW[15]
Grain	374.0	44,293.3
Hay	353.0	33,872.2
Spuds	95.0	12,817.2
Pasture	63.0	1,352.9
Grass	53.0	2,108.7
Corn	19.0	1,256.2
Mud Lake (canal co)	8.0	2,389.5
River	6.0	545.3
Mixed circles	3.0	1,196.8
Orchard	2.0	25.5
Pond	2.0	292.1
River	1.0	104.6
Cemetery	1.0	16.0
Canola	1.0	278.7
Radish	1.0	36.3
Flood	1.0	12.1
Total	983.0	100,597.4

Table Twenty-Two: 2007 Program Participant Estimation of Crop Type x Total Acres presents field installer estimates of 2007 Program participant crop types x acres[16]. Again, these are estimates are constrained by the same parameters indicated in Table Twenty-One. In addition, data accuracy is further constrained by having to estimate the size of the total acres under cultivation at a particular site. Accordingly, attempts to synch-up avoided MW as reported in Table Twenty-One should be avoided.

[14] Note: these estimates represent information about 2007 participating sites in the PacifiCorp service territory. Specifically these data represent sites where the crop type has been indicated by field installation teams. Sites where crop type has not been identified by field installation teams are eliminated as part of the query.

[15] Data includes results from both Scheduled Forward as well as Dispatchable initiatives

[16] The query extracting these data required that both 'crop type' and 'acreage' fields be populated with values from field installation teams. Where either or both fields were left blank the values were not included in the resultant table.

Table Twenty-Two
2007 *Program* Participant Estimation of Crop Type x Total Acres

Crop Type / Application	Total Acres
Grain	79,801.0
Hay	62,432.0
Spuds	18,117.0
Grass	4,787.0
Pasture	3,671.0
Corn	2,465.0
Mixed circles	1,600.0
Canola	260.0
Radish	130.0
Flood	100.0
Cemetery	15.0
Orchards	6.0
Mud lake (canal co.)	N/A
Total Acres	173,384.0

Load profile data (CB-67 (Big Grassey))

Throughout the control period, Company SCADA data were collected and used in preparing impact analyses. Transmission Circuit Breaker #67 (CB-67 (Big Grassey)) aggregates four distribution substations (Hamer, Sandune, Camas and Dubois) which were known to have a significant number of *Program* participants. A significant portion of the participants in this area, however, participated in the Dispatchable (Schedule 72A) program. Hence the impact of the Scheduled Forward component is difficult to observe. Nevertheless, SCADA values were taken and logged at 20-second intervals for periods when dispatches were executed. Virtually all of the 13 'Dispatch Events' had identical profiles. Two of those profiles are described and presented in the illustrations below.

Illustration One (Big Grassey Transmission Load Profile July 12, 2007 (CB 67-'Big Grassey')) depicts grid impacts as a function of both Scheduled Forward (Schedule 72) and Dispatchable (Schedule 72A) options. What is noteworthy is (1) the magnitude of the load shifting effect as depicted in the difference between control and non-control hours and (2) the impact of 'load shaping' as a function of the combined impacts of the Scheduled Forward and Dispatchable program components. This shaping capability is important as it provides Rocky Mountain Power with greater optionality and control over the grid in systematically meeting load requirements during summer peak periods.

The 'shaping' is dramatically different than that experienced with the use of the electronic timers alone. The aggregate impact of electronic timers results in a hard edge in the SCADA profile as opposed to a more gradual load shape with the combined used of the electronic timers and the 2-way control equipment. For comparison and illustrative purposes of this 'edging effect' 2006 load data is provided in Illustration Two.

Illustration One

Big Grassey Transmission Load Profile July 12, 2007 (CB 67-'Big Grassy')

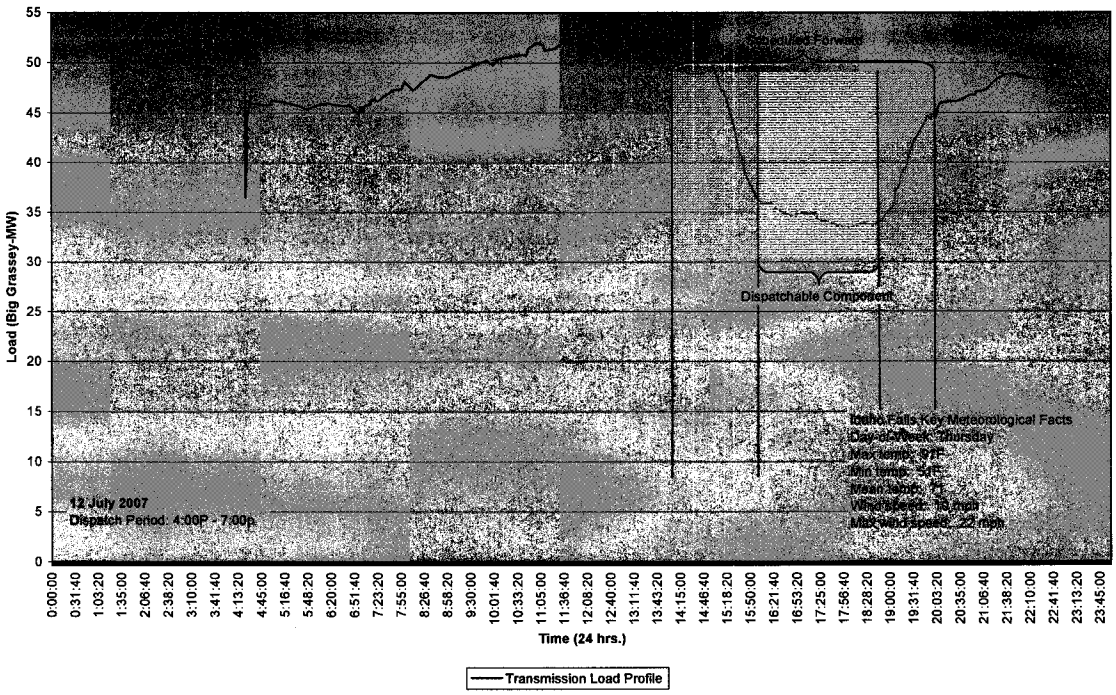


Illustration Two

Schedule 72 Idaho Irrigation Load Control-Average Daily Load Curve:

Control vs. Non-Control Periods for July & August 2006 (CB 67-'Big Grassy')

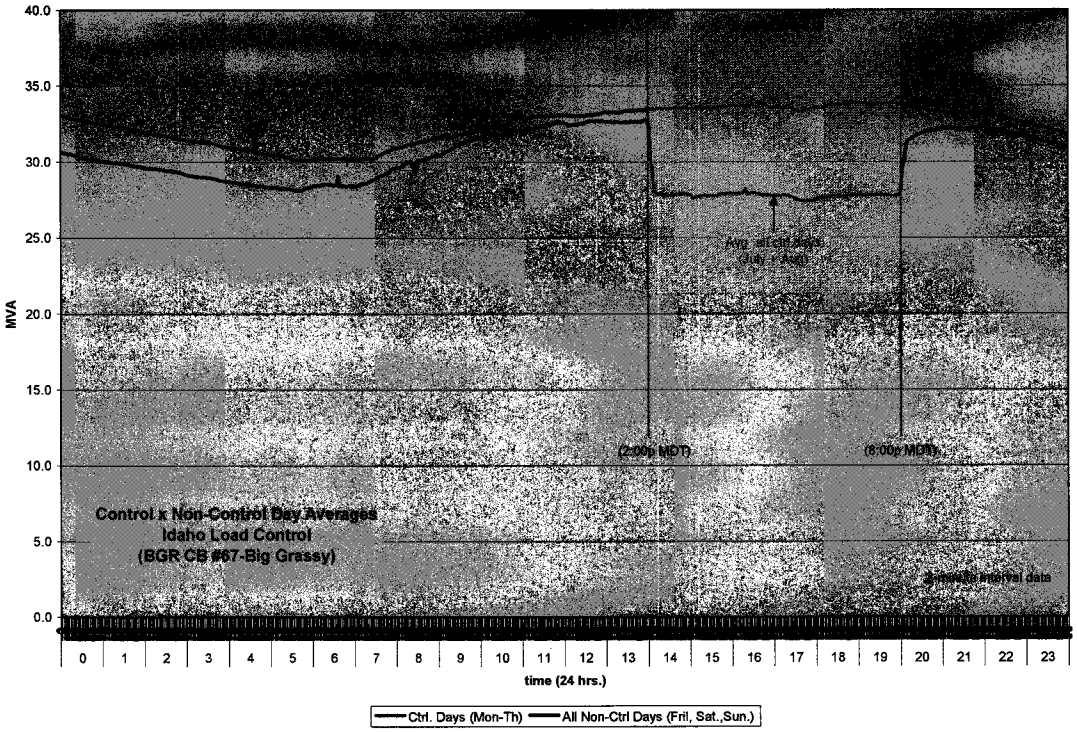
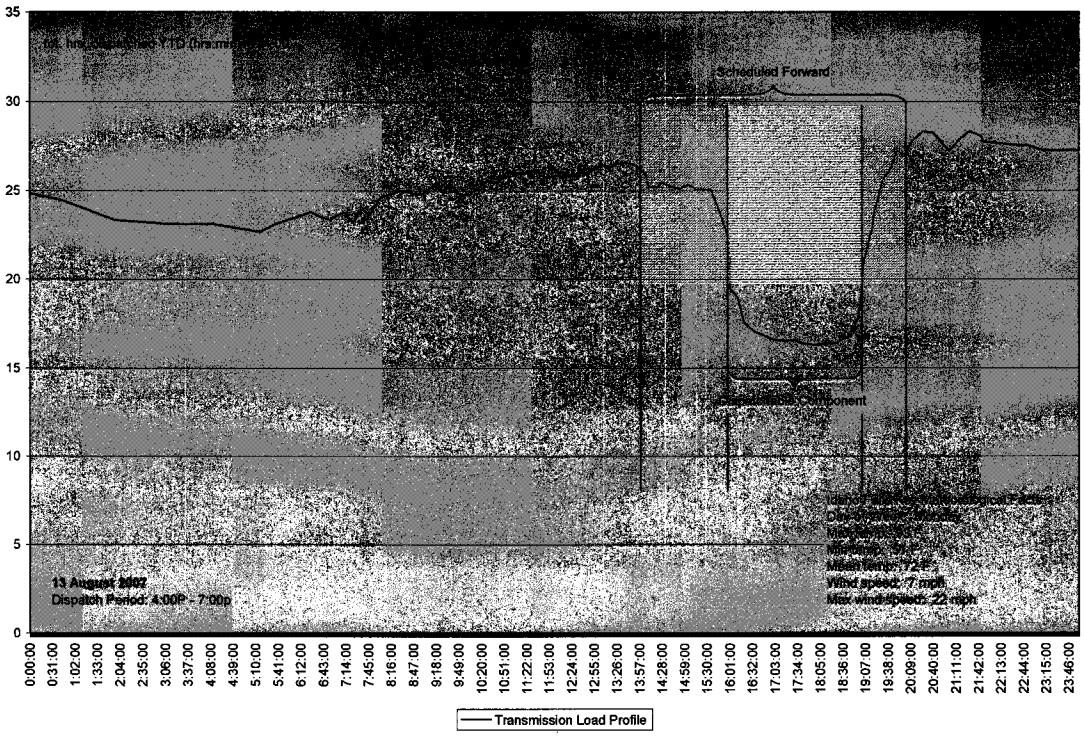


Illustration Three (Big Grassey Transmission Load Profile August 13, 2007 (CB 67-'Big Grassy')) plots Big Grassy 20-second interval load data for August 13. Again, what is instructive is that nearly all 13 'Dispatch Events' incur the identical load profile with only minor perturbations.

Illustration Three

Big Grassey Transmission Load Profile August 13, 2007 (CB 67-'Big Grassy')



Load profile data (Total Rocky Mountain Power Southeast Idaho unadjusted FERC load data)

Illustration Four (Total PacifiCorp Hourly Idaho Loads (July): Schedule 72A Idaho Irrigation Load Control-Dispatch Days vs. Non-Control Days) plots the total Company Southeast Idaho Service Territory average hourly interval load data for the first two-thirds of July[17]. Data is segregated by dispatch days (Dispatchable component only) and non-dispatch days (including scheduled forward dispatches).

Additional Southeast Idaho Service Territory average hourly interval load data plots will be provided below. In evaluating these data a cautionary note is warranted in their interpretation. The aggregate Southeast Idaho load profile data provides some indication as to impacts as a function of the Irrigation Load Control program. These data, however, should not be interpreted as being conclusive evidence for or against operational efficacy as there are a wide variety of activities impacting the electric grid other than irrigation alone. Where appropriate, attempts will be made to provide interpretation / rationale of the data that is presented. Also, and at the time of the preparation of this report, only preliminary June and July FERC data were available.

[17] 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 Four
Total PacifiCorp Hourly Idaho Loads (July):
Schedule 72A Idaho Irrigation Load Control-Dispatch Days vs. Non-Control Days

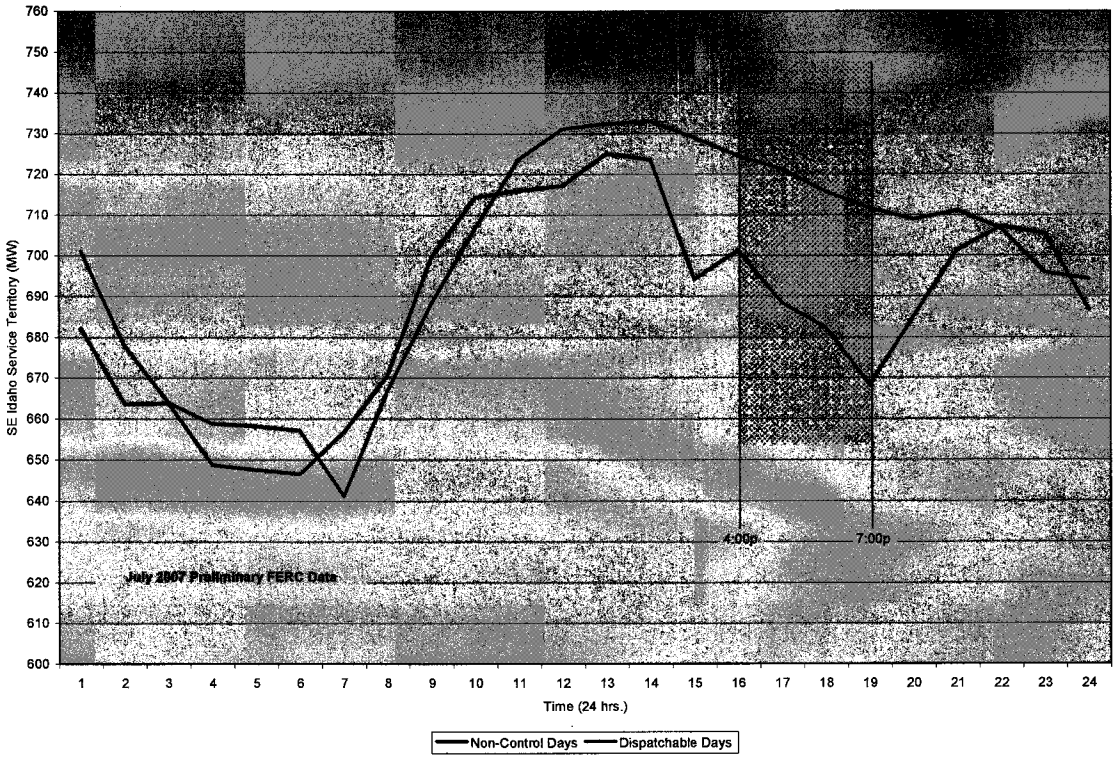


Illustration Five (Total PacifiCorp Hourly Idaho Loads (June+July): Schedule 72 Idaho Irrigation Load Control-Scheduled Forward Days vs. Non-Control Days) plots the total Southeast Idaho Service Territory average hourly interval load data for June and July. Data is segregated by the Scheduled Forward dispatch days (Monday thru Thursday inclusive) and non-dispatch days (Friday thru Sunday inclusive)[18].

Two important findings are revealed in these data. First, Friday and weekend loads are approximately 75MW less than Monday thru Thursday loads. This is not surprising but it does confirm what is typical for the Rocky Mountain Power system. Second, there is an approximate 25MW 'depression' on weekday afternoons during the control period. This highly unusual pattern is unique to agricultural loads as residential and commercial loads are 'temperature-following' and would otherwise be expected to rise during the heat in the afternoon. This unique agricultural-pattern is likely the result of two culprits: (a) the six-hour Scheduled Forward dispatch block and (b) grower tendency to minimize water loss to evapotranspiration during the heat of summer afternoons by reducing, where possible, irrigation turns during those hours.

[18] There were zero days in June where the Dispatchable resource was executed. Ergo, only Scheduled Forward Dispatch Events are reported for this particular plot.

Illustration Five

Total PacifiCorp Hourly Idaho Loads (June+July):

Schedule 72 Idaho Irrigation Load Control-Scheduled Forward Days vs. Non-Control Days

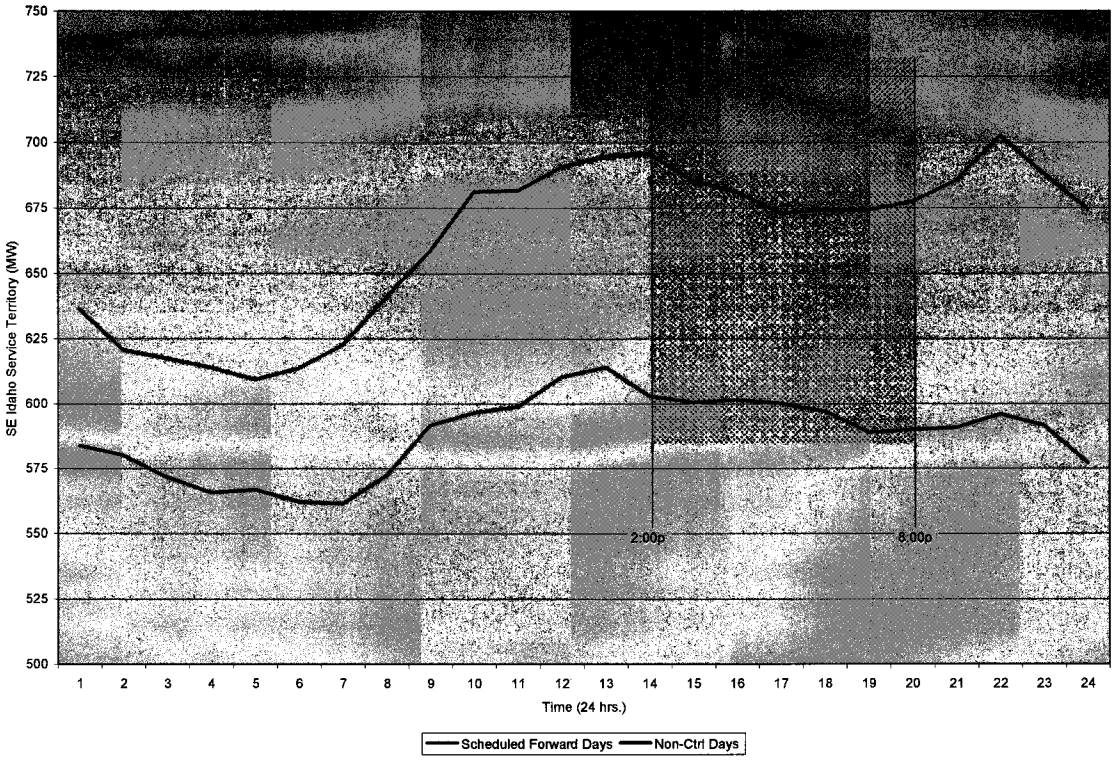


Illustration Six (Total PacifiCorp Hourly Idaho Loads Comparing Schedule 72 + Schedule 72A to Non-Control Days) plots the total Southeast Idaho Service Territory average hourly interval load data for the first two-thirds of July. Data is segregated by the Scheduled Forward dispatch days (Monday thru Thursday inclusive) + Dispatchable dispatch days vs. non-dispatch days (Friday thru Sunday inclusive + 6 July which was a Dispatchable day and which fell on Friday). The results of these plots are somewhat confusing as we would have anticipated an additive drop in load when compared to the non-control days. It is likely that the less-than-remarkable difference is due to the fact that non-control days are only marginally higher than the control periods as a function of the naturally occurring reduction in Friday and weekend loads. Again, it is, at best, difficult to draw conclusions on these data taking into consideration grid vagaries, agricultural practices, meteorological considerations and on-going program operations when the entire Southeast Idaho load is considered.

Illustration Six

Total PacifiCorp Hourly Idaho Loads Comparing Schedule 72 + Schedule 72A to Non-Control Days

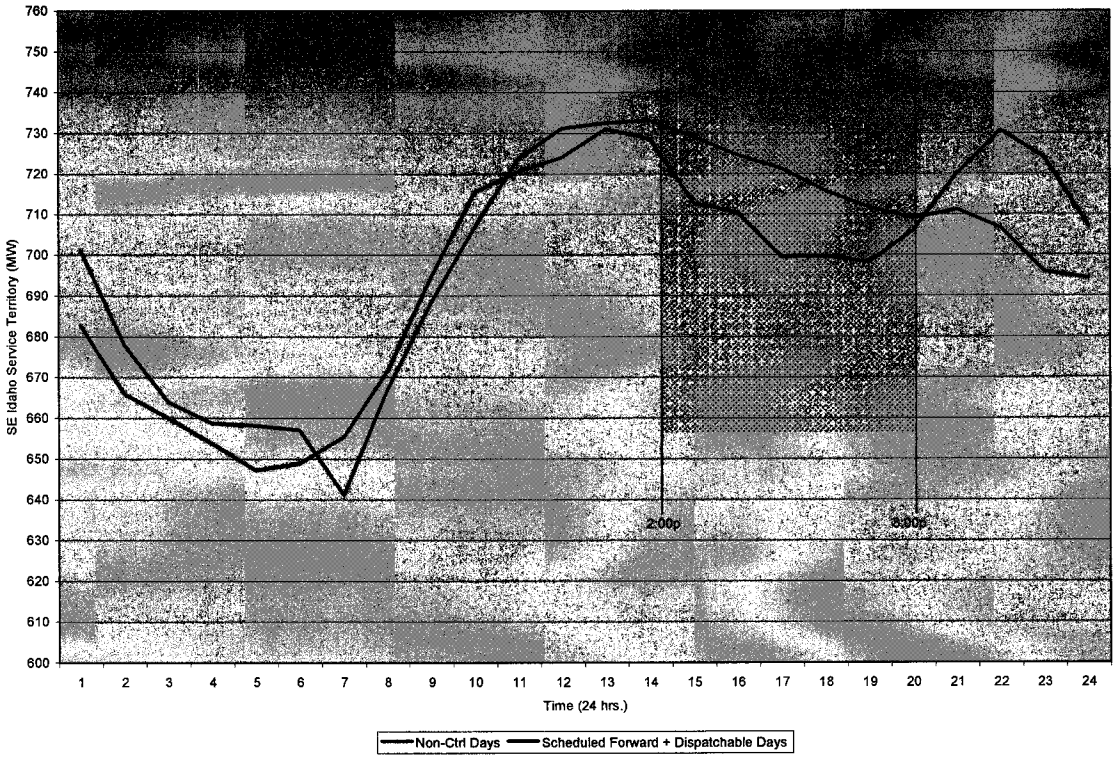
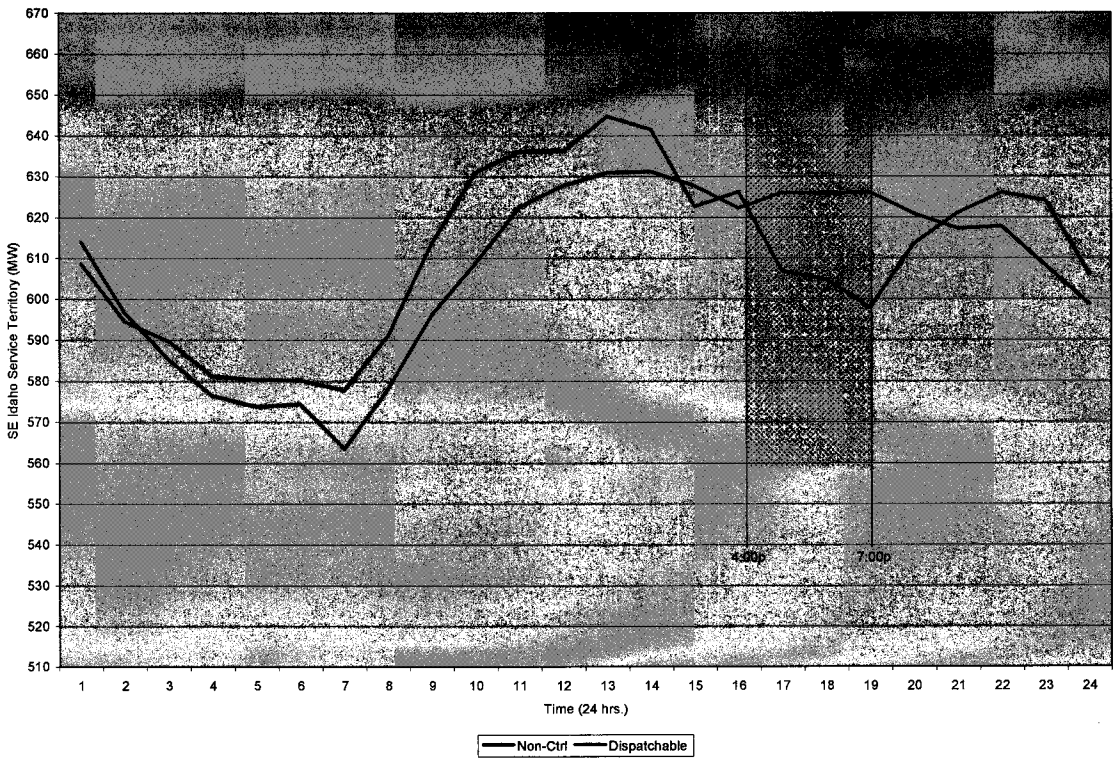


Illustration Seven (Total PacifiCorp Hourly Idaho Loads Comparing July Total Schedule 72A (Dispatchable) to Non-Control Days) plots the total Southeast Idaho Service Territory average hourly interval load data for July. Data is segregated by the Dispatchable dispatch days vs. non-dispatch days (Friday thru Sunday inclusive). The results of these plots are interesting in that they indicate the efficacy of the dispatchable component to shift loads to shoulder and off-peak hours.

Final note on SCADA plots: taking the previous six illustrations into consideration the impact of irrigation load control is difficult to deny. By the same token, using SCADA data it is difficult, at best, to precisely determine the magnitude of its impact. At this point what can be provided is nominal data on what occurred.

Illustration Seven

Total PacifiCorp Hourly Idaho Loads Comparing July Total Schedule 72A (Dispatchable) to Non-Control Days



Cost-effectiveness analyses

Cost-effectiveness calculations were prepared for each of the four standard utility industry tests in a manner consistent with the methodologies described earlier. In this evaluation, however, full program costs for both Schedule 72 and Schedule 72A together with benefits from both program components are used as the basis for the evaluations. Benefits and Costs for Schedule 72A upon which calculations are prepared are presented in Table Twenty-Three below[19].

[19] Again, to the extent possible, costs have been allocated by the respective Schedule initiative

Table Twenty-Three
2007 Benefit / Cost Categories & Values–Schedules 72 & 72A

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$1,500.00	$/kW-yr avoided	$49.56
Program evaluation	$2,268.75		
Field / Equip / Db admin. expenses	$747,664.85		
Participation credits	$1,752,930.47		
Program management	$ 80,144.00		
Reporting	$0.00		
Total	$2,584,508.07		

As shown in Table Twenty-Four, the combined initiatives (Schedule 72 + Schedule 72A) pass the TRC, Utility and Ratepayer Tests. The Program also passes the Participant Test. However, since the participant incurs no costs the benefit/cost ratio would be infinite. Accordingly for the Participant Test the value is indicated as 'N/A' in the Benefit/Cost Ratio column.

Table Twenty-Four
2007 Cost-effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$4,896,212	$831,578	$4,064,635	5.89
Utility	$4,896,212	$2,584,508	$2,311,704	1.89
Ratepayer	$4,896,212	$2,584,508	$2,311,704	1.89
Participant	$1,752,930	$0.00	$1,752,930	N/A

Conclusions & Recommendations

The pilot Dispatchable initiative was positively received by the growers and significantly oversubscribed for the 2007 irrigation season. There were four factors that can be attributed to the favorable reception:

1. The fundamental value proposition / program design that permits growers to opt-out of Dispatch Events. Each and every one of the growers indicted that without the opt-out feature it is highly unlikely the pilot would have been positively received and participation would have continued to hover in the range of 50MW. The ability to opt-out is central to receiving favorable grower acceptance and making the Dispatchable initiative work.

2. Growers appear to have preliminarily concluded that high water use row crops (corn and potatoes) are not adversely affected (either quality or yield impacts) by participation in the Dispatchable program. The Irrigation Management Team will continue to closely monitor grower perceptions relative to yield / quality impacts as it relates to program participation.
3. Fewer dispatch hours. If either quality or yield were affected by the Dispatch Events growers simply would not participate. As one grower indicated they can lose the entire participation credits in just a couple of bushels per acre less yield. The current program design appears to be much better tailored to agri-business needs and requirements and yet still provide grid benefits as measured by SCADA data.
4. Initiating and maintaining a local presence of agri-irrigation / information systems specialists and irrigation equipment specialists to ensure the initiative's success. Throughout the pilot, growers continued to reassure Rocky Mountain Power of their commitment to stand behind the irrigation initiative as knotty technical issues and operational considerations required attention. Both the growers and the Irrigation Team understood that it would likely take three or more growing seasons until farm managers and growers alike were fully inculcated with the remote control irrigation management systems and equipment. Providing skilled, local and professional resources on a 7 x 24 basis to train, council, instruct and / or troubleshoot problems as they arose was viewed as important as the technology itself. Growers indicated a favorable response to a joint (growers / Rocky Mountain Power) long-term partnership. Nearly all growers point to this partnership and commitment to technology innovation as an important underpinning to program success.

Based on the results and findings from the 2007 Irrigation Load Control initiative Rocky Mountain Power advances the following four considerations as they relate to the 2008 effort and beyond.

1. The Dispatchable load control initiative should be a permanent offering in the portfolio of grower participation options. As part of the settlement reached with the Idaho Irrigation Pumpers Association in the company's general rate case, Rocky Mountain Power will modify the current tariff to reflect ongoing Program operation and a revised level of incentive credits. The tariff will include the appropriate operational modifications gleaned from the 2007 pilot and agreed to as part of the stipulated settlement.
2. Due to (1) the difference in committed participation hours, (2) the inability to opt-out and (3) the availability of advanced control technology it is likely that very few, if any, growers will participate in the Scheduled Forward initiative. Nevertheless, the choice to participate in this option should continue to be made available to growers at least through the 2008 irrigation season. The intent would be to evaluate the Scheduled Forward option at the conclusion of the 2008 season to determine its efficacy for subsequent program years.
3. Allow growers to participate year-over-year without having to re-sign-up each year. Allowing growers to participate without having to re-indicate their intent to participate would expedite operational considerations and allow the Irrigation Team to prepare for the ensuing irrigation season in a more expeditious fashion. The current practice of having growers re-initiate their intent to participate in the Irrigation Load Control Program is awkward and confusing to growers and adds an administrative burden that could and should be removed to improve efficiencies.

4. Year-round operation. The magnitude (both scope and complexity) of the program requires practices and procedures beyond the efforts that have driven program design, development and implementation thus far. For instance, Rocky Mountain Power cannot reasonably expect to send notifications to growers by mid-January; receive response back by mid-February and have units fully installed and operationally ready by June 1. As noted above, Rocky Mountain Power received criticisms relative to timeliness of installs, customer service and program operations. The criticism was largely 'self-inflicted' as the Irrigation Management Team elected to expand the pilot beyond the original 45 MW in an attempt to meet grower desire for participation.

   Implementing and managing over 100 MW employing a technology which requires a substantial change in established irrigation practices has and will, for at least the next three years, remain a year-round effort as growers transition to new irrigation practices and habits. Moreover, using the advanced, remote 2-way technology requires Rocky Mountain Power to maintain an on-going relationship with growers, farm managers and ultimately participating pump / pivot sites throughout the irrigation season. Today, operational practices are radically different than in previous program years under a Scheduled Forward offering. For instance, initial and on-going training of the growers and of their farm managers in equipment use and operation requires significant effort that must continue if program operations are expected to be prudently implemented and robustly operated.

   Near-term operation of the Irrigation Load Control Program will entail more hours for management, and additional outside resources for troubleshooting, training and customer service. Consequently, Rocky Mountain Power expects a 3x or more increase in delivery expenses over the next several years. Anticipated expense increases will come from year-round staffing to meet work load requirements, conversion of the pilot to a permanent program, grower training along with the management of a much larger network. The Irrigation Management Team will, of course, continue to do everything possible to retard program delivery costs.

   While this transition will be occurring over the next several years Rocky Mountain Power expects and is fully prepared to judiciously maneuver through the often not-so-clear complex operational changes to meet the challenges. Rocky Mountain Power also expects that changes may also be reflected in tariff considerations. As tariff-related issues arise Rocky Mountain Power will bring them forward to the Commission for consideration.

Attachment One

Dispatchable Load Control Initiative Grower Questionnaire

Idaho Irrigation

Dispatchable Load Control Initiative (IPUC Tariff 72A)

My primary responsibility with this farm is as follows:
(circle only one)

1. Farm owner / operator
2. Manager of individual farm managers
3. Farm manager
4. Administrative / office operations
5. Information technology / financial

Program introduction / terms 'n conditions	Select one option only		
How did you first learn about the Dispatchable program? (circle only one)	Bob Smead	Brad / Ty (field installers)	Irrigation Hot Line
	Other_____		
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
When first contacted, the Dispatchable program was explained so that I understood what was involved?	☐	☐	☐
I understood what would be required of me (grower) / farm managers and/or office personnel?	☐	☐	☐
I understood what Rocky Mountain Power's responsibility would be?	☐	☐	☐
Based on the information I was able to make an informed decision about my participation?	☐	☐	☐

Additional comments as they relate to *Program introduction / terms 'n conditions*

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_____

_____

_____

Selecting and scheduling site installations			
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
Appropriate information was provided in helping me to select participating sites?	☐	☐	☐
While I wasn't entire clear about which sites to include after a bit of further explanation / understanding I was able to make an informed decision?	☐	☐	☐
I was kept abreast of when field installers would be working on my irrigation equipment?	☐	☐	☐
Where required, the Rocky Mountain Power irrigation team worked with me in identifying and selecting participating sites?	☐	☐	☐
The importance of pump site naming / identification and how the software would work?	☐	☐	☐
Where required, the reason for excluding certain sites was described to me?	☐	☐	☐
When there were delays in getting units installed on my equipment the reasons were explained?	☐	☐	☐

Additional comments as they relate to *Selecting and scheduling site installations*

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Field installation activities / processes			
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
Field installers/electricians understood and respected farm practices as it relates to…			
Communicating which sites would be visited and approximate times of those site installations?	☐	☐	☐
Knowledge of irrigation equipment?	☐	☐	☐
Proper and safe treatment of equipment?	☐	☐	☐
Removal of miscellaneous site debris (wire nuts, wire, tape, etc) the site was left in a clean, orderly fashion?	☐	☐	☐
Proper and appropriate entry into and exit from fields to access pivot / pump sites?	☐	☐	☐
Leaving the pump in the operational position that it was prior to their working on the equipment?	☐	☐	☐
When there were problems troubleshooters were dispatched in a timely manner?	☐	☐	☐
When I asked about how the control equipment worked I was provided with a clear description?	☐	☐	☐
Troubleshooting problems and related problems with the control technology were quickly defined and explained to me?	☐	☐	☐

Additional comments as they relate to *Field installation activities*

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_____

'Dispatch Event' operations			
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
The frequency (how often) 'Dispatches' were called were what I was led to believe would occur?	☐	☐	☐
The duration of 'Dispatches' were what I was led to believe would occur?	☐	☐	☐
Generally I was able to work within the frequency and duration of 'Dispatch Events'?	☐	☐	☐
The time-of-day 'Dispatch Events' occurred (3:00p-7:00p) were easily accommodated into my irrigation schedule?	☐	☐	☐
'Day-ahead' notifications were sufficient to allow me to adjust my water schedule?	☐	☐	☐
Notifications the 'morning-of' the 'Dispatch Event' were helpful reminders?	☐	☐	☐
Had dispatches been executed in June I would have had to 'opt-out' of a greater number of 'Dispatch Events'.	☐	☐	☐
Based on notification information I was able to make an informed decision about my participation in 'Dispatch Events'?	☐	☐	☐
Having the ability to opt-out of 'Dispatch Events' gives me confidence that I am in control and will likely participate in the future if a dispatch option is offered?	☐	☐	☐

Additional comments as they relate to *Dispatch Event operations*

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Training			
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
The training on how to use the software was helpful in getting me knowledgeable on how the system works?	☐	☐	☐
Using the phone system to control irrigation sites was more convenient than the Internet?	☐	☐	☐
Training materials / information was organized and appropriate to meet my needs?	☐	☐	☐
During training my questions were answered and/or comments taken into consideration by those providing the training?	☐	☐	☐
When I got stuck and called for support it was provided in a timely fashion?	☐	☐	☐
Call center people could log-on and see what I was seeing and could appropriately respond to my questions and/or direct me in what I needed to do as it relates to the software...the phone?	☐	☐	☐

What changes would you like to see in the software to made to make the user interface more accessible and easier to navigate?

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Additional comments as they relate to *Training*

_____

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M2M Control Equipment			
For each question below check only a single box	**Agree**	**Middle Road**	**Disagree**
Information was provided on how the equipment worked?	☐	☐	☐
After using the equipment for some time I am confident I will gain additional confidence in its reliability?	☐	☐	☐
I believe I will use the equipment for the management of my regular irrigation turns?	☐	☐	☐
The control equipment is a physically acceptable 'bolt-on' to the standard pump / pivot equipment?	☐	☐	☐
The 'Irrigation Hot Line' was helpful in answering questions I had as they related to the equipment?	☐	☐	☐
Members of the irrigation management team were helpful in answering questions I had as they related to the equipment?	☐	☐	☐
I found the web-site software intuitive and easily understandable?	☐	☐	☐
The phone system menu was easily negotiated?	☐	☐	☐

Additional comments as it relates to *M2M Control Equipment*

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