LAW OFFICES OF

RACINE OLSON NYE BUDGE & BAILEY
CHARTERED

201 EAST CENTER STREET
POST OFFICE BOX 1391
POCATELLO, IDAHO 83204-1391

TELEPHONE (208) 232-6101
FACSIMILE (208) 232-6109

www.racinelaw.net

SENDER'S E-MAIL ADDRESS: elo@racinelaw.net

W. MARCUS W. NYE
RANDALL C. BUDGE
JOHN A. BAILEY, JR.
JOHN R. GOODELL
JOHN B. INGELSTROM
DANIEL C. GREEN
BRENT O. ROCHE
KIRK B. HADLEY
FRED J. LEWIS
MITCHELL W. BROWN
ERIC L. OLSEN
CONRAD J. AIKEN
RICHARD A. HEARN, M.D.
DAVID E. ALEXANDER
LANE V. ERICKSON
PATRICK N. GEORGE
SCOTT J. SMITH
STEPHEN J. MUHONEN
BRENT L. WHITING
JUSTIN R. ELLIS
JOSHUA D. JOHNSON
JONATHON S. BYINGTON
DAVE BAGLEY
CAROL TIPPI VOLYN
THOMAS J. BUDGE
CANDICE M. MCHUGH

BOISE OFFICE
101 SOUTH CAPITOL
BOULEVARD, SUITE 208
BOISE, IDAHO 83702
TELEPHONE: (208) 395-0011
FACSIMILE: (208) 433-0167

IDAHO FALLS OFFICE
477 SHOUP AVENUE
SUITE 203A
IDAHO FALLS, ID 83402
TELEPHONE: (208) 528-6101
FACSIMILE: (208) 528-6109

COEUR D'ALENE OFFICE
250 NORTHWEST
BOULEVARD, SUITE 106A
COEUR D'ALENE, ID 83814
TELEPHONE: (208) 765-6888

ALL OFFICES TOLL FREE
(877) 232-6101

LOUIS F. RACINE (1917-2005)
WILLIAM D. OLSON, OF COUNSEL

September 27, 2007

RECEIVED
2007 SEP 28 AM 9:53
IDAHO PUBLIC
UTILITIES COMMISSION

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

Re: PAC-E-07-05

Dear Mrs. Jewel:

Enclosed for filing please find nine copies of Direct Testimony of Anthony J. Yankel (with exhibits), Mark Mickelsen, and Stanley G. Searle.

Thank you for your assistance.

Sincerely,

ERIC L. OLSEN

ELO
Enclosures
cc: Service List

Eric L. Olsen ISB# 4811
RACINE, OLSON, NYE, BUDGE &
BAILEY, CHARTERED
P.O. Box 1391; 201 E. Center
Pocatello, Idaho 83204-1391
Telephone: (208) 232-6101
Fax: (208) 232-6109

RECEIVED
2007 SEP 28 AM 9:53
IDAHO PUBLIC
UTILITIES COMMISSION

Attorneys for the Idaho Irrigation Pumpers Association, Inc.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)	**CASE NO. PAC-E-07-05**

IDAHO IRRIGATION PUMPERS' ASSOCIATION, INC.'S NOTICE OF SERVICE

You will please take notice that IDAHO IRRIGATION PUMPERS' ASSOCIATION, INC., by and through their attorneys of record, served the Direct Testimony and exhibits of Anthony Yankel, Mark Mickelsen, and Stanley C. Searle upon the parties to this action by providing said documents to the following individuals in the manner specified in the attached Certificate of Service below.

Respectfully submitted this 27th day of September, 2007.

RACINE, OLSON, NYE, BUDGE &
BAILEY, CHARTERED

By _____
ERIC L. OLSEN
Attorneys for the Idaho Irrigation Pumpers Association, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 27th day of September, 2007, I served a true, correct and complete copy of the Direct Testimony of Anthony Yankel (with exhibits), Mark Mickelsen, and Stanley C. Searle to each of the following, via U.S. Mail postage prepaid, e-mail or hand delivery:

Jean Jewell (9 copies) Idaho Public Utilities Commission 472 W. Washington Street P.O. Box 83720 Boise, Idaho 83720-0074 E-mail: jean.jewell@puc.idaho.gov	U.S. Mail
James R. Smith Monsanto Company P.O. Box 816 Soda Springs, ID 83276 E-mail: jim.r.smith@monsanto.com	U.S. Mail
Maurice Brubaker Katie Iverson Brubaker & Associates 17244 W. Cordova Court Surprise, AZ 85387 kiverson@sconsultbai.com	U.S. Mail
Anthony Yankel 29814 Lake Road Bay Village, OH 44140 E-mail: tony@yankel.net	U.S. Mail
Idaho Irrigation Pumpers Association, Inc. c/o Lynn Tominaga P.O. Box 2624 Boise, ID 83701-2624 E-mail: lynn_tominaga@hotmail.com	U.S. Mail

Randall C. Budge Racine, Olson, Nye, Budge & Bailey, Chtd. P.O. Box 1391 Pocatello, Idaho 83204-1391	Hand Delivery
Brian Dickman Rocky Mountain Power 201 South Main, Suite 2300 Salt Lake City, Utah 84111 Email: brian.dickman@pacificorp.com	U.P.S. Overnight delivery
Dean Brockbank Justin Brown Rocky Mountain Power 201 South Main, Suite 2300 Salt Lake City, Utah 84111 E-mail: dean.brockbank@pacificorp.com E-mail: justin.brown@pacificorp.com	U.S. Mail
Tim Buller Agrium, Inc. 3010 Conda Road Soda Springs, Idaho 83276 E-mail: tbuller@agrium.com	U.S. Mail
Conley E. Ward Michael C. Creamer Givens Pursley LLP 608 W. Bannock Street P.O. Box 2720 Boise, ID 83701-2720 E-mail: cew@givenspursley.com	U.S. Mail
Dennis Peseau, Ph.D. Utility Resources, Inc. 1500 Liberty Street S.E., Ste. 250 Salem, OR 97302 E-mail: dpeseau@excite.com	U.S. Mail
Scott Woodbury Deputy Attorney General Idaho Public Utilities Commission 472 W. Washington (83702) P.O. Box 83720	U.S. Mail

Boise, ID 83720-0074

Brad M. Purdy
Attorney at Law
2019 N. 17th Street
Boise, ID 83702 — U.S. Mail

Kevin B. Homer, Esq.
1565 South Boulevard
Idaho Falls, ID 83404 — U.S. Mail

ERIC L. OLSEN

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)))))	CASE NO. PAC-E-07-05

IDAHO IRRIGATION PUMPERS

DIRECT TESTIMONY

OF

ANTHONY J. YANKEL

SEPTEMBER 28, 2007

1 Q. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

2

3 A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My
4 address is 29814 Lake Road, Bay Village, Ohio, 44140.

5

6 Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL
7 BACKGROUND AND PROFESSIONAL EXPERIENCE?

8

9 A. I received a Bachelor of Science Degree in Electrical Engineering from
10 Carnegie Institute of Technology in 1969 and a Master of Science Degree in Chemical
11 Engineering from the University of Idaho in 1972. From 1969 through 1972, I was
12 employed by the Air Correction Division of Universal Oil Products as a product design
13 engineer. My chief responsibilities were in the areas of design, start-up, and repair of new
14 and existing product lines for coal-fired power plants. From 1973 through 1977, I was
15 employed by the Bureau of Air Quality for the Idaho Department of Health & Welfare,
16 Division of Environment. As Chief Engineer of the Bureau, my responsibilities covered a
17 wide range of investigative functions. From 1978 through June 1979, I was employed as the
18 Director of the Idaho Electrical Consumers Office. In that capacity, I was responsible for all
19 organizational and technical aspects of advocating a variety of positions before various
20 governmental bodies that represented the interests of the consumers in the State of Idaho.
21 Since 1979, I have been in business for myself. I am a registered Professional Engineer. I
22 have presented testimony before the Federal Energy Regulatory Commission (FERC), as

well as the State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Idaho Irrigation Pumpers Association (IIPA).

Q. WHAT ISSUES WILL YOU ADDRESS IN THIS PROCEEDING?

A. I will address the following issues in this case:

- Inequities of the present Revised Protocol interjurisdictional allocation methodology as it punishes all Idaho customers for the system benefit provided by the Irrigation Load Curtailment Program;
- The lack of representation of Irrigation Load Curtailment customers in the Company's load research program results in excessive costs being allocated to the Irrigators;
- The loss of the BPA credit will have a sobering impact upon both Irrigators and Residential customers. Programs need to be developed or better aligned with costs in order for Irrigators to take better control of their overall costs while paying for the costs they place upon the system.

Q. PLEASE GIVE AN OVERVIEW OF THE RECOMMENDATIONS THAT YOU WILL BE MAKING IN THIS CASE.

A. I will make the following recommendations:

- Because of the situs treatment of the curtailment credit given to Irrigators under Schedule 72, the revenue requirement for Residential and all other Idaho customers is increased, the more Irrigators join in the Load Curtailment Program. I recommend that the Irrigator Load Curtailment program be regarded as system benefit resources, and not treated as situs.
- The Company's load research data does not fully reflect the level of Irrigation Load Curtailment, and thus, the Company's cost of service study attributes too much demand to the Irrigators and thus, increases the allocated costs. I recommend that the Company's coincident peak data for the Irrigators be adjusted in order to reflect the actual level of Load Curtailment that is taking place. This adjustment increases the rate of return for the Irrigators. I recommend that (in keeping with the Company's proposal) that the Irrigators get no more than 2/3 of the average jurisdictional percentage increase.
- The present credit for Irrigation customers on Schedule 72 is considerably below the benefit provided to the system. I recommend that this credit be increased by $40/kW-year, in order to bring more Irrigators into the program, benefit the entire system at a cost less than avoided cost, and to provide an overall benefit to the system that is greater than what is presently being realized.

- I recommend that time-of-day rates be established for Irrigators as an additional option that could both benefit the system and the customers that choose that rate.

Interjurisdictional Treatment of Irrigation Curtailment Program

Q. HOW MUCH INTERRUPTIBILITY IS THERE GENERALLY IN THE IDAHO JURISDICTION?

A. Generally speaking, there is 67 MW of economic curtailment associated with Monsanto and 95 MW of emergency interruptibility as well. The Irrigation Load Curtailment program in the test year 2006, generally reduced peak demands by another 50 MW. This totals to 212 MW. Approximately an additional 25 MW or Irrigation Load Curtailment was expected in 2007.

Elsewhere on the system there is approximately 189 MW of interruptible load, 97 MW of curtailable load. Additionally, the Utah Cool Keeper Air Conditioning Load Control Program achieved an estimated maximum reduction in 2006 of 90 MW[1]. This totals to 376 MW. Although the Idaho Jurisdiction is allocated 6.3% of the system generation costs[2], it provides approximately 36% of the megawatts available for system interruptibility/curtailment benefits.

Q. IS THERE A PROBLEM WITH THE DISPARITY IN THE AMOUNT OF INTERRUPTION CAPABILITY IN IDAHO VERSUS THE REST OF THE SYSTEM?

A. There would not be a problem if allocations were performed on a basis that reflected the system benefits of these various interruptibility/curtailment programs. Under

[1] See Response to IIPA Request 1.13.
[2] Exhibit 11, page 10.1 lists Idaho's SG allocation factor as 6.3064%

1 the Revised Protocol method (which is presently being used to do jurisdictional allocations
2 on the PacifiCorp system), interruptions and curtailments that occur to special contract
3 customers are treated as a system benefit. This is appropriate. However, in spite of the fact
4 that the Idaho Irrigation Curtailment program reduced peak demand by approximately 50
5 MW in 2006 (and was expected to provide 75 MW in 2007)[3], it is labeled as DSM and
6 simply allocated situs to Idaho. Thus, although the benefits of such interruptions are spread
7 system wide, the cost of the program is kept within the jurisdiction that is supplying the
8 system benefit. In Idaho's case, it actually increases the Idaho jurisdiction costs, while
9 providing the system a benefit.
10
11 Q. HOW DOES SITUS TREATMENT OF THE IDAHO IRRIGATION LOAD
12 CURTAILMENT PROGRAM NEGATIVELY IMPACT IDAHO RATEPAYERS?
13
14 A. The July 2007 Report prepared for the Company entitled "Assessment of
15 Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources"
16 (DSM Report) has information regarding costs and benefits of curtailment programs. It
17 states that there is a system benefit of $98/kW-year for a program that can reduce demand by
18 1 kW. Given the Idaho Jurisdiction's GS (System Generation) allocation factor of 6.3%, this
19 means that for every kW of demand that is reduced because of the Idaho Irrigation Load
20 Curtailment program, the Idaho Jurisdiction gets a benefit from such a decrease of $6.18 ($98
21 x 0.063064 = $6.18).

[3] According to the Company's Response to IPUC 24-d, there will be approximately 50 MW per month on Schedule 72A and 50 MW on Schedule 72 which is split evenly between the two curtailment periods.

On the other side of the ledger are the expenses that bring about this benefit. There are certainly some administrative costs, installation costs, and ongoing field expenses. One of the most obvious expenses is the "credit" that is paid to Irrigators for participation in the program. Currently, that credit is set at $11.19/kW-year[4]. In the Company's filing, this credit is treated as entirely situs, meaning that the Idaho Jurisdiction pays $11.19 (plus its share of the other related expenses) in order to receive a benefit of $6.18. There is a net cost to Idaho of $5.01 for every kW of demand that is saved for the system ($11.19 - $6.18 = $5.01).

This result is completely unjust for the Irrigators who are "given" a credit and then have their overall rates increased to cover the credit that they rightfully deserve. Effectively, the Irrigators are taking money out of their left pocket and putting it in their right pocket in order to pay themselves for the $98/kW-year benefit that they provide to the system. It's even more unjust that this jurisdictional cost of $5.01 is allocated 22% to the Residential customers. The net impact on the Idaho Residential class is that they pay $1.11 for each $98 of system benefit caused by the Irrigator and receive nothing in return[5].

Q. WHAT DO YOU RECOMMEND TO CORRECT THIS PROBLEM?

A. This is the first full general rate case in the Idaho Jurisdiction of PacifiCorp in a very long time. Because of this, the Revised Protocol Interjurisdictional Allocation has been around for a couple of years, but never used to establish rates in Idaho. I recommend that for purposes of this case that this portion of the Revised Protocol be ignored and a more

[4] Based upon Schedule 72, the 6 hour/day and 2 day/week option.
[5] ($11.19 cost – ($98 x 6.063064) benefit) x 22.2% allocator = $1.11 cost.

appropriate "system" treatment of these costs be utilized. Over the long-term, this defect in the Revised Protocol should be corrected, such that it reflects the treatment of the benefit of the Irrigation Load Curtailment program in a manner similar to the treatment of the benefit of the Monsanto interruptible program.

Q. UNDER THE REVISED PROTOCOL METHOD, MONSANTO IS TREATED AS A FIRM CUSTOMER, ITS INTERRUPTIBLE LOAD ADDED BACK FOR COST OF SERVICE PURPOSES AND A SEPARATE CREDIT IS GIVEN FOR THE INTERRUPTIBILITY. SHOULD THE INTERRUPTIBLE PORTION OF THE IRRIGATION LOAD BE ADDED BACK TO THE IRRIGATION LOAD FOR PURPOSES OF COST OF SERVICE?

A. That would be in keeping with the Revised Protocol. However, unlike Monsanto, the source of this data is less clear. There are two different sources (and thus values) of Irrigation interruptible load. In order to be consistent, with the rest of the data, the load to be added back to the Irrigators must come from the same load research data that established their overall usage. I raise this concern because the interruptibility of the Irrigators is undervalued in the load research data. Although the Company's 2006 "Schedule 72 Idaho Irrigation Load Control Progress Report" (2006 Schedule 72 Report) indicates that the Company avoided in July on Tuesdays/Thursdays as high as 46.7 MW and on Mondays/Wednesdays 47.5 MW (See Exhibit 301), the load research data represents far less interruptions. If the same load research data is used to add back the interruptibility, there will be a wash and the problem will go away. If a different source of data (i.e., from the 2006

Schedule 72 Report) is used to add back the interruptibility portion, it is possible to attribute load to Irrigators which does not exist.

Load Research Data and Irrigator Interruptibility

Q. DOES THE COMPANY'S LOAD RESEARCH DATA FULLY REFLECT THE IRRIGATION LOAD CURTAILMENT PROGRAM?

A. No. In fact, the Irrigation load research data was not set up to reflect the Irrigation Load Curtailment program. The load research meters for Irrigators were put in place in 1999, long before the Irrigation Load Curtailment program went into place[6].

Q. HOW WELL WAS THE IRRIGATION LOAD CURTAILMENT PROGRAM REPRESENTED IN THE LOAD RESEARCH DATA?

A. The Company has indicated that 18 (32%) of the Irrigation customers in its load research sample were on the Irrigation Load Curtailment program[7]. However, a closer review indicates that the Irrigation Load Curtailment program was under-represented in the 2006 data, based on demand. Two of those 18 sample customers only had limited data and this data was not used. Additionally, the load research data indicates that four of these sample customers did not undergo interruptions in 2006. As indicated on Exhibit 302, of the 12 sample customers that were being interrupted, the following breakdown by strata occurred:

Stratum 1	2 customers
Stratum 2	1 customer
Stratum 3	9 customers
Stratum 4	zero customers

[6] See Response to IPUC Request 25.

1 Although three of the smaller customers are represented in this sample, there are no large
2 (Stratum 4) customers represented.
3 Of most significance is that most of these sample customers are on the
4 Monday/Wednesday interruption schedule, and even at that, they only reflect an interruptible
5 load of 44.7 MW of potential interruption. In contrast to this level, the Company's 2006
6 Schedule 72 Report (Exhibit 301, page 2) indicated that at the beginning of the season it had
7 50.8 MW of firm, scheduled resources each day. Thus, the Monday/Wednesday load
8 research data reflected only 88% of the potential Irrigation curtailment on the day of the
9 week which defined the coincident peaks in June and July. Of more concern is the
10 Tuesday/Thursday interruption group where the load research data only reflects 17.6 MW of
11 the 50.8 MW of potential of interruption.
12
13 Q. HOW SHOULD THIS INFORMATION BE USED TO CORRECT THE
14 IRRIGATION PEAK LOAD DATA?
15
16 A. If interrupted Irrigation load is going to be added back to the Irrigator usage in
17 the cost of service study, then, in order to be consistent, the interruptible data must come
18 from the load research. If one of the sample customers was operating around the time of a
19 system peak (but was interrupted), then this interruptible load should be added to the
20 Irrigation firm peak demand. Exhibit 303 lists the load research predicted interruptions for
21 the June and July peaks as 44.1 MW and 35.6 MW respectively. Exhibit 304 lists the load
22 research predicted interruptions for the August and September peaks as 8.8 MW and 2.4 MW

[7] Response to IIPA Request 5.1 lists 18 samples being on the load curtailment program, while the other 39 were not.

respectively. If the Commission decides to add back any interruptions to the Irrigators' demand (in order to be consistent with the Monsanto treatment), the Irrigation coincident peak loads should be increased by 44.1, 35.6, 8.8, and 2.4 MW for the summer months of 2006.

If the Irrigation Load Curtailment data is going to be simply used in a standard cost-of-service study to reflect actual usage at the hour of peak of each month, then the data should be adjusted to reflect the fact that the load research sample does not fully represent the extent of the interruptions on the system—the Irrigation peak loads (at sales level) in the Company's cost of service study should be adjusted as follow:

June	+ 6.8 MW
July	- 11.1 MW
August	- 28.5 MW
September	- 44.3 MW

In this manner, the Company's load research data and ultimately the cost-of-service study will reflect the level of curtailment by month that was calculated to occur in the Company's 2006 Schedule 72 Report.

Revenue Spread To The Irrigators

Q. WHAT DOES THE COMPANY'S FILING SUGGEST WITH RESPECT TO THE RATE OF RETURN AND RATE SPREAD TO THE IRRIGATORS?

A. The Company's filing lists the rate of return for the Irrigators at 6.03%, which is 1.05 times greater than the jurisdictional average rate of return of 5.76%. Since the filing in this case, some errors have been addressed. After correcting these errors, Monsanto's rate of return went up and the rate of return for other customer groups went down. The Company's Response to Monsanto Request 9.6 now has the rate of return for Irrigators at 6.06%—equivalent to the new jurisdictional average of 6.07%.

Q. IS THE COMPANY'S LOAD RESEARCH DATA APPROPRIATE TO USE IN THE DEVELOPMENT OF THE RATE OF RETURN FOR THE IRRIGATORS?

A. No, for two reasons. First, as pointed out above, from purely the perspective of adequately covering the Load Curtailment program, the load research sample does not fully reflect the curtailable load on Monday's and Wednesday's, which impacts the June and July data. For the months of August and September, (when the peaks occurred on Tuesdays) less than 15% of the curtailable load is reflected in the load research data.

Second, there are major calibrations made to the Irrigation load research data as follows:

June	117%
July	100%
August	107%

1 September 144%

2 The weighted average calibration during these four months was 111%, i.e., the sample load
3 research data was adjusted upward by 11% in order to be brought in line with actual energy
4 usage of the entire population of Irrigators.

5

6 Q. WHAT REVENUE SPREAD DO YOU RECOMMEND TO THE
7 IRRIGATORS?

8

9 A. Based on the above, it is obvious that there are some serious data issues
10 associated with the Irrigation load. These data issues all tend to lower the Irrigators' rate of
11 return. In spite of these issues, the Irrigators have been showing a rate of return at or above
12 the jurisdictional average. Company witness Griffith has proposed that Schedule 10 get 2/3
13 of the average jurisdictional percentage increase. Given the additional problems I have
14 pointed out with respect to the Company's demand data for Schedule 10, it would not be
15 appropriate to give the Irrigators more than 2/3 of the jurisdictional average percentage
16 increase as initially proposed by the Company.

Rate Design

Q. WHAT IS THE IMPACT OF THE RECENT LOSS OF THE BPA CREDIT ON THE IRRIGATION CUSTOMERS?

A. In the filing, the revenue from Schedule 10 was only listed[8] as $35,569,932. There was an additional $3,834,747 collected because of the RMA adjustment. The BPA credit for Irrigators listed[9] in the Company's filing was $17,555,537. Thus, the Irrigators effectively paid only $21,849,142[10]. Absent any increase in this case to the Irrigators, the Irrigators' effective rate will jump $17.6 million or 80% above what they have been paying[11]. Although such a rate increase is intolerable for any customer group, there are limited options in this case that would supply a benefit similar to that of the BPA credit. Additionally, the only other large customer class in this jurisdiction is the Residential class and it lost its BPA credit[10] of $13,101,921. Instead of directly replacing the BPA credit, the Commission must look elsewhere in order to find methods for mitigating the impact of this loss.

Q. IF THE COMMISSION CANNOT DIRECTLY REPLACE THE BPA CREDIT, HOW CAN IT GO ABOUT MITIGATING THE IMPACT OF THE LOSS OF THE BPA CREDIT FOR THE IRRIGATORS?

---

[8] Company Exhibit 35, page 4
[9] Company Response to IIPA Request 1.31
[10] $35,569,932 + $3,834,747 - $17,555,537 = $21,849,142
[11] Increasing the amount paid by $17,555,000 over the $21,849,000 paid in the past is an 80.3% increase.

A. One of the simplest and most straightforward ways to mitigate the impact of the loss of the BPA credit would be to provide interruption/curtailment options that are fully cost justified. By developing appropriated interruption/curtailment programs, the Irrigators will be given the opportunity to better control their own costs, while providing a benefit to the system. First, I recommend that the present Irrigation Load Curtailment Credit Rider (Schedule 72) be priced more appropriately to reflect the benefit that the Company claims to be accruing to the system. Second, I recommend that a Time-Of-Day (TOD) rate be established as another option for the Irrigators.

Irrigation Load Control Credit Rider (Company Study)

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE EXISTING IRRIGATION LOAD CURTAILMENT PROGRAM ON THE PACIFICORP SYSTEM.

A. At present Schedule 72 is the main vehicle for Irrigators which consists of fixed/pre-scheduled times and days for interruptions of Irrigation load. There is also a pilot program (Schedule 72A) that is a "Company Option" program that is just completing its first season of operation. Because there is little data compiled regarding the Company Option program, I will focus my comments on the designated day (Schedule 72) program.

Under the designated day program, there are three options/levels of interruptibility for Irrigators:

* 6 hours/day for 2 days/week
* 3 hours/day for 2 days/week; and
* 3 hours/day for 4 days/week.

1 During 2006, approximately 91% of the curtailable Irrigation load was under the "6 hour/day
2 for 2 days/week" option. Because of this, as a general matter, I will focus most of my
3 comments on this "6 hour/day, 2 day/week" option. The present credit under Schedule 72 for
4 this option varies monthly as follows:

5	June	$3.05 /kW month
6	July	$3.64/kW month
7	August	$3.49/kW month
8	September	$1.01/kW month

9 The total credit (assuming that an Irrigator operates each month of the summer season) is
10 $11.19 per kW. Although Schedule 72 has an allowance for an energy credit as well as a
11 demand credit, thus far, the energy credit has always been set at zero.
12
13 Q. HAS THE IRRIGATION LOAD CURTAILMENT PROGRAM UNDER
14 SCHEDULE 72 ENJOYED A GREAT DEAL OF SUCCESS?
15
16 A. Success is a relative measure. According to the Company's 2006 Schedule 72
17 Report during the Irrigation Season, there was an average of 50.8 MW of firm scheduled
18 curtailment at the beginning of the season[12] and an average of 47.1 MW at the end of the
19 season. This level of curtailment is significant when compared to the jurisdictional
20 coincident demands used to allocate demand costs[13] during the summer months that range
21 from 492—666 MWs.

[12] Exhibit 301, page 2.
[13] Company Exhibit 11, page 10.12

However, as pointed out in the 2006 Schedule 72 Report[14], only 20.1% of the total available irrigation sites participated. Of more concern, the Report made the following observation:

> The reader should note that the Commission approved a ~21% increase in 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)*. ... 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. (Emphasis added)

Q. CAN THE CURRENT INTERRUPTIBILITY CREDIT OFFERED IN SCHEDULE 72 IN ANY WAY OFFSET THE LOSS OF THE BPA CREDIT?

A. Only to a very minor extent. Both the BPA credit and the interruptibility credit existed in 2006 for approximately 20% of the Irrigators and approximately 25% of the Irrigation load[15]. Thus, for those customers that were already receiving the interruptibility credit, the loss of the BPA credit is simply a loss that cannot be offset by the present interruptibility credit. However, for the other 75% of load that was not previously on Schedule 72, the movement to an Irrigation Load Curtailment program could help offset some of the loss.

Q. HOW MUCH OF THIS LOSS COULD BE OFFSET?

---

[14] Exhibit 301, page 1.

[15] According to the 2006 Schedule 72 Report at page 2 the participating load hit a maximum of 100,132 kW during July 2006; according to Company Exhibit 30, Tab 5, page 13, the Irrigation non-coincident peak @ input was 429,860 kW (374,874 assuming losses of 1.14668); thus, 26.71% participated (100,132 / 374,874 = 0.2671)

1 A. That is not an easy question to answer with any precision. It must be
2 understood that, unlike the BPA credit, there is an offsetting cost associated with Schedule 72
3 that did not exist with the BPA credit. The BPA credit was simply a credit, with no
4 corresponding costs to the Irrigator. However, there are definite costs associated with the
5 Irrigation Load Curtailment program—some are tangible and some are intangible. On the
6 tangible side, there are clearly additional labor costs associated with restarting irrigation
7 equipment after an interruption and also additional labor costs associated with operating the
8 irrigation system on weekends or other times when the curtailed pumping activity must be
9 made up. There are also intangible costs such as the fact that occasionally equipment
10 problems arise that prevent restarting the equipment, crops could be excessively stressed and
11 yield/profits lowered, etc. No matter what the specific reason causing the participation to
12 drop in 2006 (in spite of a 21% increase in the credit), the economics of the cost/benefit ratio
13 had to come into play and 12.6% of the Irrigators from 2005 decided not to participate in
14 2006.
15 In order to put some ballpark limits on this answer, I will assume that there is only
16 benefit associated with Schedule 72 and no costs to the Irrigators (in spite of the fact that
17 12.6% of the sites in 2006 decided that the costs exceeded the benefits). As stated above, I
18 will assume that 25% of the 2006 Irrigation load participated in the program. According to
19 the 2006 Schedule 72 Report, the total credits paid out were $925,577. If it were possible, to
20 induce the rest of the Irrigators to participate under the same rates as specified in Schedule
21 72, the increase in the credit would be $2.8 million[16]. Even assuming that this $2.8 million

[16] $925,577 x (75% / 25%) = $2,776,731

1 credit increase comes at no cost to the Irrigators, such an increase in the level of this credit is
2 a far cry from the loss of the BPA credit that amounts to $17.6 million.
3
4 Q. ARE THE PRESENT CREDITS LISTED UNDER SCHEDULE 72
5 APPROPRIATE?
6
7 A. No, from two perspectives. First, as demonstrated in the Company's 2006
8 Schedule 72 Report, in spite of an increase in the level of the credit, participation declined.
9 There is an interest in the program on the part of the Irrigators, but they are either finding a
10 cost/benefit ratio that is very low or one of little value to them. From a policy standpoint, it
11 makes little sense to offer programs that have only marginal benefits to the customers.
12 As pointed out above, on July 11, 2007 Quantec issued its Report to the Company
13 entitled "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other
14 Supplemental Resources" (DSM Report). In the Company's DSM Report, it was clearly
15 demonstrated that the benefits of the Irrigation Load Curtailment program far exceeds the
16 costs associated with that program (even under the Report's assumption of a doubling of the
17 credit paid). From a policy standpoint, it is inappropriate to have a DSM type resource with
18 such a large advantage to the system being under utilized by the customers because the credit
19 being paid is such a small fraction of the benefit being realized.
20
21 Q. PLEASE ELABORATE ON THIS DSM REPORT.
22
23 A. As stated in the Executive Summary:

> This study's principal goal is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources, comprised of capacity-focused program options (defined throughout this report as Class 1 or Class 3 DSM resources), energy-efficiency products and services (defined as Class 2 DSM resources, and other "supplemental" resources such as solar, combined heat and power, and dispatchable standby generation. The analysis of resource potential in this study are augmented by an examination of the benefits of consumer awareness and education initiatives (class 4 DSM resources) and an analysis of how future structural changes, such as technological innovation, macroeconomic conditions, and public policy, might affect the findings and conclusion of this study.

Thus, the DSM Report was designed to (and virtually did) cover all aspects of DSM and alternative resources. The Irrigation Load Curtailment program was viewed as one of only three "firm" options that represent a Class 1 resource. Of these three Class 1 options, the Irrigation Load Curtailment program had the lowest costs per unit of avoided capacity and in fact these costs were calculated to be less than half of the cost of the next closest option. The Irrigation Load Curtailment program was calculated to have a levelized cost of $47/kW-year (based upon a $20/kW-year credit) compared to an avoided cost of capacity in the Rocky Mountain Power region of $98/kW-year.

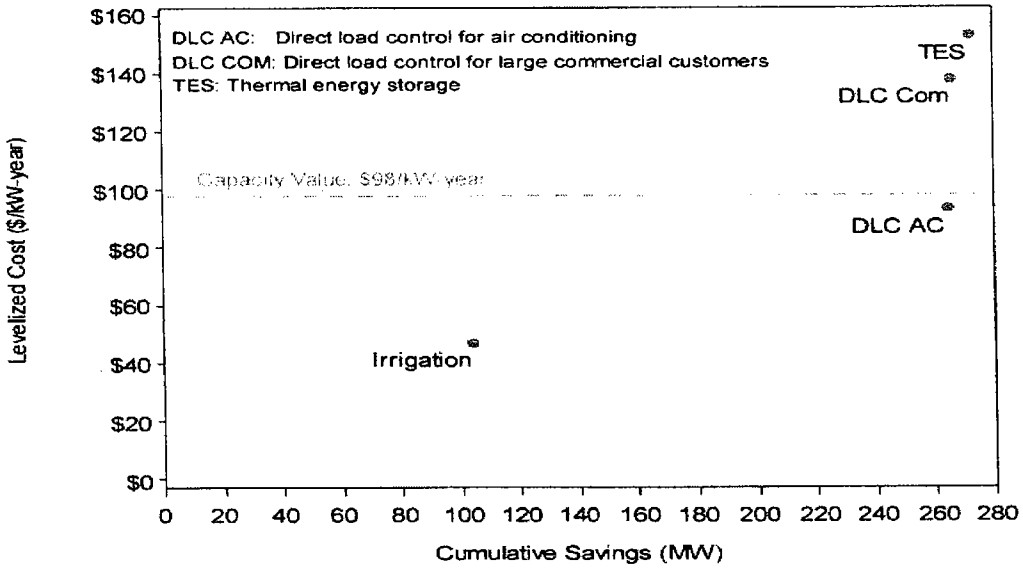
Q. DOES THE QUANTEC REPORT DEMONSTRATE THE RELATIONSHIP BETWEEN THE COSTS OF AVOIDED CAPACITY, THE LEVELIZED COST OF THE IRRIGATION LOAD CURTAILMENT PROGRAM, AND OTHER CLASS 1 PROGRAMS?

A. Yes, it does. The Report contains a figure that demonstrates that the Irrigation Load Curtailment program not only is far more cost effective than any other Class 1 DSM

1 program, but that the other programs have costs that are near, or actually exceed the avoided

2 capacity cost of $98/kW-year. The following figure from that Report is reproduced below:

Figure 6. Class 1 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2027)



3

4 Q. WHAT COMPONENTS MAKE UP THE IRRIGATION LOAD

5 CURTAILMENT LEVELIZED COST OF $47/KW-YEAR FOUND IN THE REPORT?

6

7 A. The Report assumes a number of costs in the development of this levelized

8 cost figure of $47/kW-year. They include:

9	Standard Program Development	$400,000 one time
10	Installation costs	$1,000 per new participant
11	Marketing costs	$500 per new participant
12	On-going maintenance	$10 per kW in the program
13	Incentive Payment	**$20 per kW** in the program

14 I do not agree with all of these costs, but at this point I only wish to address the Incentive

15 Payment value which is obviously contrary to what is presently being paid to Irrigators.

16 Even the DSM Report recognizes the fact that this Incentive Payment level is above what is

17 actually being paid when it states on page 37:

> Although PacifiCorp currently pays $11/kW-year for incentives (2006 program year), participation level assumptions are based on a higher incentive amount of $20/kW-year in recognition that greater penetration will require higher incentives and the emergence of the dispatchable control option is expected to increase the value of the control to PacifiCorp.

Without consideration of an Incentive Payment, the levelized avoided cost would be only $27/kW-year. Given the capacity value of $98/kW-year in the Rocky Mountain Power service area, the Incentive Payment could be $71/kW-year, before the avoided capacity cost of $98/kW-year would be reached. If the levelized avoided cost for the Irrigation Load Curtailment program were $98/kW-year, it would mean that the cost of this program would be only slightly higher than the Company's levelized cost ($93/kW-year) of its Direct Load Control program for air-conditioning, but significantly below the Company's levelized cost ($138/kW-year) of its Direct Load Control program for large commercial customers.

Q. GIVEN THE FACT THAT THE COMPANY'S STUDY INDICATES THAT THE IRRIGATION LOAD CURTAILMENT CREDIT COULD BE INCREASED BY A FACTOR OF ALMOST "7" BEFORE THE COST OF THE PROGRAM WOULD EQUAL THE CAPACITY VALUE OF THESE INTERRUPTIONS, WHAT LEVEL OF CREDIT DO YOU RECOMMEND IN THIS CASE?

A. It is clearly a loss to the system (and to the Irrigation customers in particular) to have only 20% participation in a program that provides a savings of $98/kW-year, but only costs the Company $27/kW-year (not counting the credit payment). Given that the present cost of the program (less credit paid) is $27/kW-year and the avoided capacity cost is $98/kW-year, the difference available for a credit payment is $71/kW-year. At the moment,

1 the credit payment is $11/kW-year, leaving another potential $60/kW-year available for
2 credit payments. I recommend that in this case that 2/3 of this additional available credit
3 ($40/kW-year) be added to the existing credit being given to the Irrigators. The total credit
4 would thus be $51.19/kW-year ($11.19 + $40.00 = $51.19). I make this recommendation in
5 part as an initial movement towards the full benefit of the program and in part as a
6 replacement of the BPA credit.
7
8 Q. HOW DOES AN INTERRUPTIBILITY CREDIT OF $51.19/KW-YEAR
9 COMPARE WITH THE LOSS OF THE BPA CREDIT?
10
11 A. An interruptibility credit of $51.19/kW-year is on a par with, but does not
12 fully make up for the loss of the BPA credit. During 2006, the BPA credit amounted to
13 $17.6 million. The Irrigation Load Curtailment program in 2006 (representing 25% of the
14 Irrigation load or an average billing demand[17] of 89,808 kW) resulted in a $0.9 million
15 reduction to the Irrigators bill. Once again, the $17.6 million BPA credit came without costs,
16 while the Load Curtailment credit has costs that are not addressed in this analysis. If we
17 assume full participation in the Load Curtailment program of the average billing demand[18] of
18 342,412 kW, then at a credit of $51.19/kW-year, the overall credit would be $17,528,000.
19

[17] According to page 2 of the 2006 Schedule 72 Report, the following participation rates were realized: June 82,653 kW; July 100,132 kW; August 95,322 kW; and September 81,128 kW.
[18] According to Exhibit 30, Tab 5, page 13, the following non-coincident demands were realized: June 416,761 kW; July 429,860 kW; August 388,153 kW; and September 335,773 kW. The average of these four months is 392,637 kW at input. Assuming losses at 1.14668, the average amount at sales level is 342,412 kW.

1 Q. HOW DOES THE IMPACT OF A $51.19/KW-YEAR CREDIT COMPARE
2 WITH THE LOSS OF THE BPA CREDIT AND THE IRRIGATION LOAD
3 CURTAILMENT CREDIT THAT WAS IN PLACE DURING 2006?
4
5 A. The impact of a $51.19/kW-year credit is not as large as the summation of the
6 BPA credit from 2006 ($17.6 million) plus the existing Load Curtailment credit ($0.9
7 million). The impact of a $51.19/kW-year credit not only falls $1 million short of the credits
8 received by Irrigators in 2006, but as stated before, it comes with internal costs that are not
9 included in this analysis—costs that many farmers did not find beneficial when the credit was
10 $11/kW-year.
11
12 Q. HOW DO THE BENEFITS OF A $51.19/KW-YEAR CREDIT AND FULL
13 PARTICIPATION IN THE IRRIGATION CURTAILMENT PROGRAM COMPARE
14 WITH THE PRESENT CREDIT OF $11/KW-YEAR AND PARTIAL PARTICIPATION
15 IN THE PROGRAM?
16
17 A. As a simplified example, assume that we have today 1 kW of savings at an
18 avoided cost rate of $98 and a cost of $38[19]. Thus, the present benefit to the system is a total
19 savings of $60. Now assume that the participation can be increased from 1 kW up to 4 kW.
20 The benefit is $392 ($98 x4). The cost has been increased to $78 per kW ($38 plus an
21 additional credit of $40), for a total cost of $312 ($78 x 4). Thus, the net benefit under the

[19] $47 Company calculated costs less the additional $9 in credits that was added into this figure, but not presently being paid.

new rates would be a total savings of $80 ($392 - $312 = $80). This is a 33% increase over the present net benefit to the system ($80 - $60 = $20).

Q. HOW WOULD RATES BE DESIGNED UNDER THE ASSUMPTION OF A $51.19/KW-YEAR CREDIT?

A. It may not be desirable to simply increase the demand credits each month by a factor of approximately 4.6[20] because the demand credit would far exceed the present demand charge of $4.28/kW-month. Even the increase in the credit proposed in the Company's report from $11.19/kW-year up to $20/kW-year would run into the same problem. Thus, a portion of the credit should be spread over the energy charge as is presently contemplated in Schedule 72, but previously set at zero. Based upon the existing rates, I propose that the demand portion of the credit be set at $4.28/kW during June, July, and August with the September credit at $2.14/kW (reflecting 15 days usage)—effectively removing the demand charge during each month. This demand credit would total $14.98/kW-year (of course it would be increased by whatever percentage increase is given to Schedule 10's demand charge in this case). The remaining $36.21/kW-year credit would be collected in the energy portion of the credit.

For the sake of calculating the energy portion of the credit, I will assume that all customers participate under the "6 hours/day for 2 days/week" option under Schedule 72 and that the overall credit of $51.19/kW-year would be $17,528,000. The demand credit of $5,850,204[21] would mean that the total energy credit would represent the remainder of

[20] $51.19 / $11.19 = 4.5746

[21] Exhibit 35 page 4—the demand credit would equal the entire seasonal demand charge

$11,677,866. Based upon 481,194 MWh of in-season usage, this translates into a credit of 2.42685 cents per kWh for all usage (of course it would be increased by whatever percentage increase is given to Schedule 10's energy charge in this case).

For the "3 hours/day for 2 days/week" option under Schedule 72, I simply propose at this time that the credit be set at half of the level as under the "6 hours/day for 2 days/week" option. For the "3 hours/day for 4 days/week" option under Schedule 72, I simply propose at this time that the credit be set at the same level as under the "6 hours/day for 2 days/week" option.

Because this is a significant increase over the present credit level (that is not producing as well as hoped), I would expect to get near 100% participation. Because of this, it may be appropriate to adjust the level of the credit upwards as the costs of the program in the Company's Report were only based upon a projected participation rate of 75%.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S OPTIONAL SCHEDULE 72A RATE DESIGN?

A. Schedule 72A is a good option for Irrigators and the Company. Right now the credit given to Schedule 72A is essentially the same ($11.18/kW-year) as that given under the "6 hours/day for 2 days/week" option under Schedule 72. I recommend that the new level of credit for Schedule 72-A continue to mimic that of the "6 hours/day for 2 days/week" option under Schedule 72. The demand credit should be the same as that for Schedule 72 (i.e., the demand charge that is in effect in Schedule 10) and the energy credit should be the same 2.42685 cents per kWh (increased by the average rate increase for Schedule 10).

Irrigation Load Control Credit Rider (Alternative Analysis)

Q. WHY ARE YOU PROPOSING AN ALTERNATIVE METHOD FOR CALCULATING A CREDIT FOR THE IRRIGATION LOAD CURTAILMENT PROGRAM?

A. The Company's DSM Report lacks detail with respect to the source of some of its assumptions and equations for developing the levelized cost of the Irrigation Load Curtailment program. As I stated above, I am not fully in agreement with all of the cost assumptions that were made. Therefore, I am providing an alternative analysis.

Q. UPON WHAT ARE YOU BASING THIS ALTERNATIVE ANALYSIS?

A. The Company has been operating its Idaho Irrigation Load Curtailment for over four years. It has published detailed reports each year (Schedule 72 Reports) that covered the operation of this program in 2003, 2004, 2005, and 2006. I will base my analysis on each of those four annual reports. The following table lists the annual program costs (without credits) per kW avoided:

	Costs	Avoided kW	$/kW
2003	$273,000	23,000	$11.87
2004	$307,000	32,000	$9.59
2005	$382,000	52,000	$7.35
2006	$374,000	47,000	$7.96

These are not levelized costs that are spread out over a number of years; they are simply total expenses for the year, divided by the avoided kW in that year. It should be noted that these figures contain a great deal of startup costs that will not be repeated as the program moves

1 forward. For example, once a control devise is installed, that cost will generally not have to
2 occur again for that customer for a significant amount of time. Additionally, there were
3 many timer failures in 2005 that caused much higher than expected field expenses. Because
4 of the timer failure problem in 2005, during 2006 100% of the sites that participated in the
5 program during 2005 were visited to inspect the equipment and identify faulty timers—once
6 again causing a higher than normal expense. In spite of all of these startup problems, the cost
7 of this program has dropped to less than $8/kW of avoided capacity.
8
9 Q. HOW DO THESE ANNUAL COSTS OF LESS THAN $8/KW COMPARE
10 WITH THE COMPANY'S AVOIDED COSTS?
11
12 A. Given the avoided cost in the East end of the PacifiCorp system of $98/kW-
13 year, this means that there is $90/kW-year that can be spent on "participation credits" and
14 still be at, or below the Company's avoided cost.
15
16 Q. HOW DOES THIS $90/KW-YEAR TRANSLATE INTO A CREDIT FOR
17 THE IDAHO IRRIGATION LOAD CURTAILMENT PROGRAM?
18
19 A. Under the "6 hour/day for 2 days/week" option, it takes 2 kW of load (every
20 other day) to result in 1 kW of avoided capacity. Thus, the participation credit of $90/kW-
21 year would need to be split between 2 kW in order to get the 1 kW of avoided capacity. This
22 means that a maximum annual credit of $45/kw-year could be given under Schedule 72 for
23 each kW signed up to participate.

However, under the new "Company option" Schedule 72A (which is presently experiencing an equal popularity compared with Schedule 72), it does not take 2 kW of load under contract to result in a reduction of 1 kW of actual demand. As indicated in the Company's DSM Report, it expects to be near 100% accurate with its calling of interruptions under Schedule 72A; and thus, the entire participation credit ($90/kW-year) could be returned to each participant. Assuming 50% of the customers would choose the prescheduled option of Schedule 72 and 50% would choose the Company option under Schedule 72A, this would mean that for every 2 kW of load in the program that the Company could avoid 1.5 kW of capacity (i.e., the event participation rate would be 75%). With an event participation rate of 75% and a $90/kW-year avoided cost margin available for an incentive, the credit could be as high as $67.50/kW-year ($90 x 0.75 = $67.50).

Q. BASED UPON THIS ALTERNATIVE ANALYSIS, DO YOU RECOMMEND ANYTHING DIFFERENT THAN THE $51.19/KW-YEAR CURTAILMENT CREDIT THAT YOU SUGGESTED USING THE COMPANY'S REPORT?

A. No. Given that the "6 hour/day for 2 days/week" option under Schedule 72 would justify a curtailment credit very near the $51.19/kW-year level, and given the fact that about half of the Irrigators are preferring the Company option Schedule 72A where a significantly higher curtailment credit can be justified, my original recommendation of a $51.19/kW-year credit holds. During the next case, when data is available regarding the participation in the Schedule 72A option and the Company's ability to avoid demand under

1 this option, new (and presumably higher) credits can be justified.

Irrigation Time-Of-Day Rate

Q. DOES PACIFICORP HAVE EXPERIENCE WITH TIME-OF-DAY RATES IN IDAHO?

A. Yes. There has been a Residential Time-Of-Day (TOD) rate schedule (Schedule 36) in Idaho for the last 20 years. It has been more successful than many TOD rate schedules. In this case there are 16,276 Residential customers on Schedule 36 out of a total of 54,047 total Residential customers. Approximately half (47%) of the Residential usage takes place on Schedule 36. Schedule 36 contributes less to the system peaks as demonstrated by the fact that its contribution to the 12-coincidents peaks is only 43% of the overall Residential contribution.

It is noteworthy that even during the summer months (when there is no alternative to air-conditioning) that the relative usage between super-peak hours (2:00 p.m. to 8:00 p.m.) and average usage for Schedule 36 customers is less than that for larger Schedule 1 customers that have air-conditioning potential[22]. Basically, Schedule 36 customers are shifting a portion of their usage from the super-peak to other times.

It is noteworthy to contrast PacifiCorp's Residential TOD program with that of Idaho Power's Schedule 5 (this is a program limited to one geographic area with AMR metering). According to Idaho Power's Exhibit 59, page 1 in Case No. IPC-E-07-08, there are only 86 TOD customers taking service under this program. Even for the limited availability area in which Schedule 5 is offered, this is a very low participation rate. I bring up Idaho Power's

[22] Schedule 1, Stratum 3 customers average usage was 1,276 kWh in June, 1,396 kWh in July, 1,243 kWh in August, and 1,165 kWh in September.

1 Schedule 5, not as an example to follow, but in order to put Schedule 36's success into
2 perspective.
3
4 Q. TO WHAT DO YOU ATTRIBUTE THE SUCCESS OF PACIFICORP'S
5 RESIDENTIAL TOD RATE IN IDAHO?
6
7 A. Like any program or rate schedule, there are a variety of things that contribute
8 to the success of PacifiCorp's Schedule 36 compared to Idaho Power's Schedule 5.
9 Historically, standard Residential rates in PacifiCorp's Idaho service area have been higher
10 than comparable rates in the Idaho Power service area—higher rates make alternative rate
11 designs more attractive. According to the 2006 FERC Form 1's, PacifiCorp's non-TOD
12 Residential Schedule 1 customers paid an average of 8.39 cents/kWh, while Idaho Power's
13 non-TOD Residential Schedule 1 customers paid an average of 5.97 cents/kWh.
14 Of more significance is the differential in rates between on-peak and off-peak hours.
15 If this differential is not sufficiently large, there is little incentive to shift usage from on-peak
16 hours to off-peak hours. PacifiCorp's Schedule 36's summer TOD rates[23] are simply 10.8
17 cents/kWh on-peak, and 3.7 cents/kWh off-peak, for a differential between on-peak and off-
18 peak of 7.1 cents/kWh.
19 Idaho Power's Schedule 5's summer TOD rates are more complex with three tiers
20 (on-peak, mid-peak, and off-peak), but one can readily see the differences between this rate
21 and Schedule 36. Schedule 5's highest priced, on-peak rate (1:00 p.m. to 9:00 p.m.) is 8.3
22 cents/kWh. This "highest rate" is 2.5 cents/kWh <u>less</u> than the Schedule 36 on-peak rate and

[23] All rates in this section of testimony have been rounded to one decimal point for easy of reading.

is almost as large as the entire differential of 7.1 cents/kWh in Schedule 36. Schedule 5's lowest priced, off-peak rate (9:00 p.m. to 7:00 a.m.) is 4.5 cents/kWh. This "lowest rate" is almost a penny more than the off-peak rate in Schedule 36. Schedule 5's mid-peak rate (7:00 a.m. to 1:00 p.m.) is 6.1 cents/kWh. This mid-peak rate essentially dampens any differential between the high and low cost hours—it is essentially a neutral time.

It is important to remember that PacifiCorp's Schedule 36 and Idaho Power Schedule 5 are voluntary/optional rates. Schedule 36 offers customers a significant choice differential and is successful. Idaho Power's Schedule 5 offers significantly less difference between on-peak and off-peak rates and the participation rate reflects this fact.

Q. HOW DO PACIFICORP'S SCHEDULE 36 RATES COMPARE WITH TOD RATES BEING DEVELOPED TODAY?

A. According to the Company's "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study, the new TOD rates being developed are more inverted than those being offered in Schedule 36. On page 46 of that DSM Report, it is stated:

> The TOU rates developed in recent years typically differ from those of the past in several important ways. First, most new TOU rates contain three price tiers as opposed to the two-tier rates common in many long-standing TOU programs, including those offered by PacifiCorp. This allows utilities to set high prices during their highest peak periods and offer exceptionally low off-peak prices overnight when the cost is at its lowest and supply is plentiful. The majority of hours are assigned a "mid-peak" price that is typically a slightly discounted version of the standard rate. Another change is that the duration of the peak period is typically shorter than in the past. Finally, the price differentials between peak and off-peak prices tend to be greater than in the past to encourage load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas

newer programs tend to have a differential of greater than 10 cents/kWh. For comparison, PacifiCorp's existing TOU rates offer a price differential of roughly 4.5 cents/kWh to 7.5 cents/kWh, depending on the operating utility and the season.

Q. HOW CAN THIS INFORMATION BE USED TO DEVELOP A TOD RATE FOR IRRIGATION CUSTOMERS?

A. As pointed out above, with the loss of the BPA credit, some serious thought must be given to mitigating the severe financial impact that could occur if nothing were done. A TOD rate for Irrigators is a DSM type option and is an opportunity to not simply lower the costs to the Irrigators, but to lower the overall system costs as well. Like Schedule 36, a TOD rate for Irrigators should get its own cost-of-service treatment such that the rates and benefits stand on their own.

TOD rates (as an option and not mandatory) are a feasible alternative for many Irrigation customers. However, Irrigators can not be realistically expected to follow a similar on-peak pattern as Residential customers. Instead, I recommend that something more like a super-peak price be developed in conjunction with an off-peak price. For the super-peak timeframe, I recommend the same 4-days per week as in the Irrigation Curtailment program and the same 6-hours per day (2:00 p.m. until 8:00 p.m.).

I recommend that the super-peak price be set at 15 cents/kWh and that the off-peak price be set at 4.2 cents/kWh. These rates have been chosen in order to develop a spread of over 10 cents/kWh between the super-peak and the off-peak and in order to remain revenue neutral if there is no net change in consumption patterns.

1

2 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

3

4 A. Yes.

Exhibit No. 301
Case No. PAC-E-07-05
Anthony J. Yankel
"Excerpts from "Schedule 72 Idaho Irrigation Load Control *Program* *2006 Credit Rider Initiative Final Report*"
http://www.pacificorp.com/Article/Article75535.html
20 pages

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Schedule 72 Idaho Irrigation Load Control *Program*

2006 Credit Rider Initiative Final Report

23 October 2006

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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')

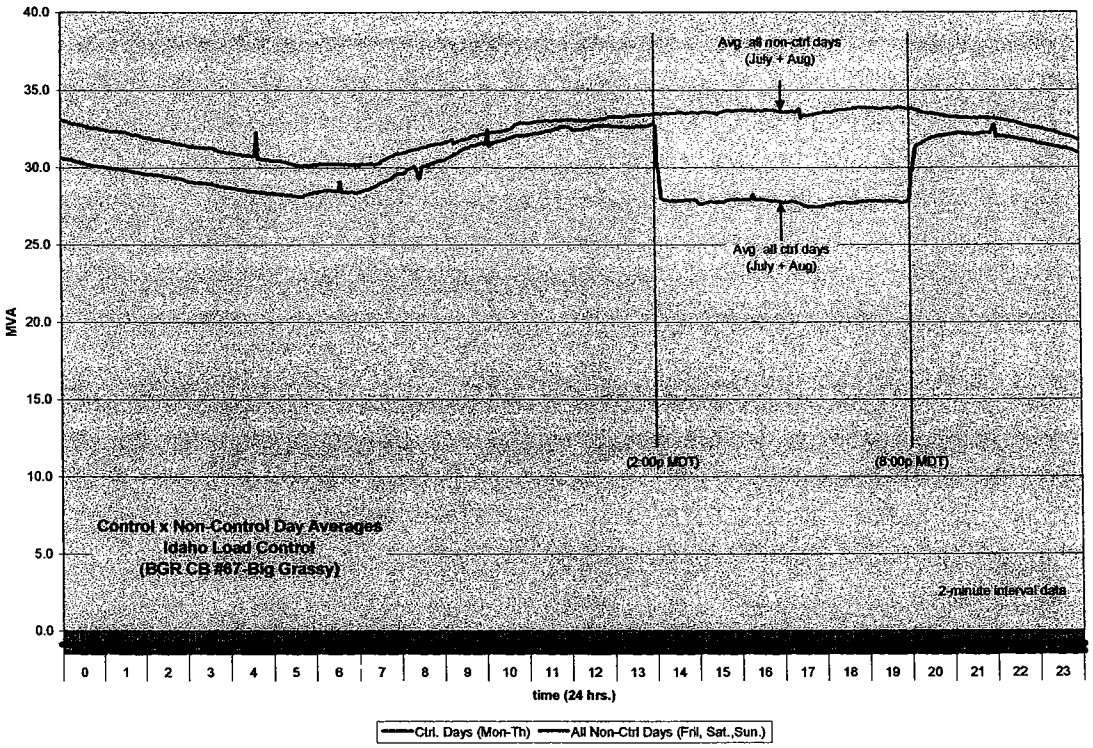


Illustration Two *(Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Control Average & Control Dispatch Schedule (M/W vs. TTH) Averages (CB 67-Big Grassy))* plots Big Grassy 120-second interval load data by the two principle control periods (M/W and T/TH). The overall average for all control 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)

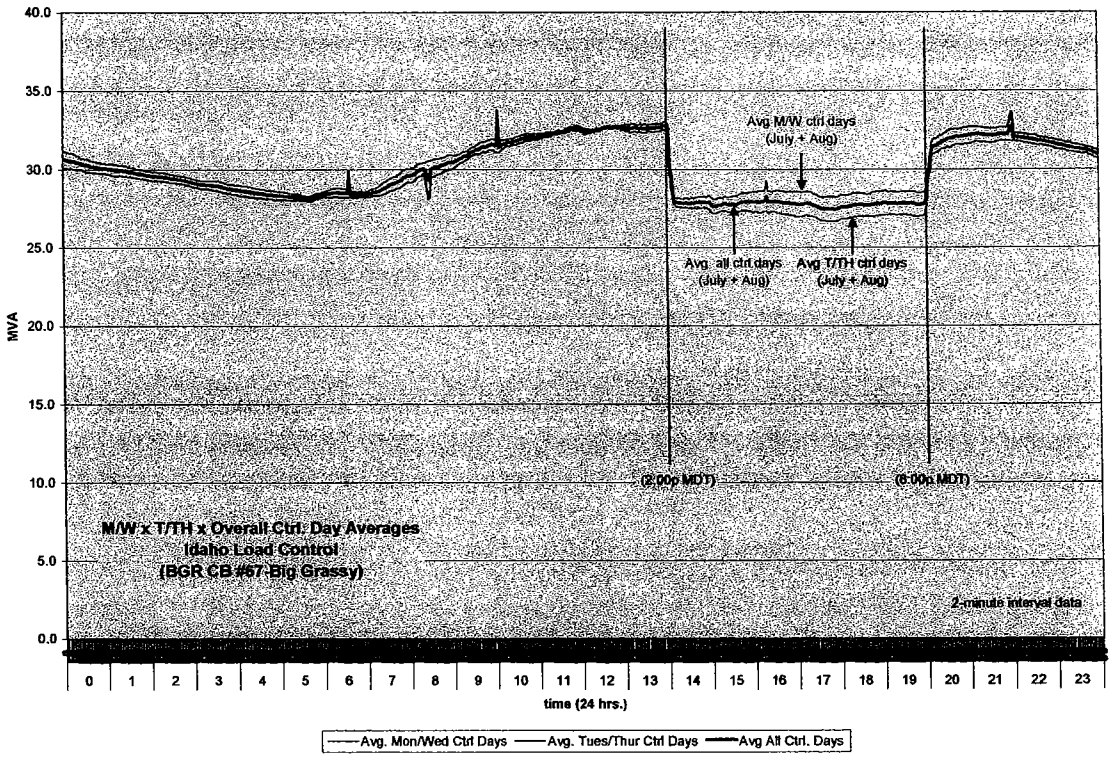


Illustration Three (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Individual Control Day-of-Week & Overall Average Control Days)* plots Big Grassy 120-second interval load data by individual day-of-week (ctrl days). Average daily control plots are also included in Illustration Three. Highlighted 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')

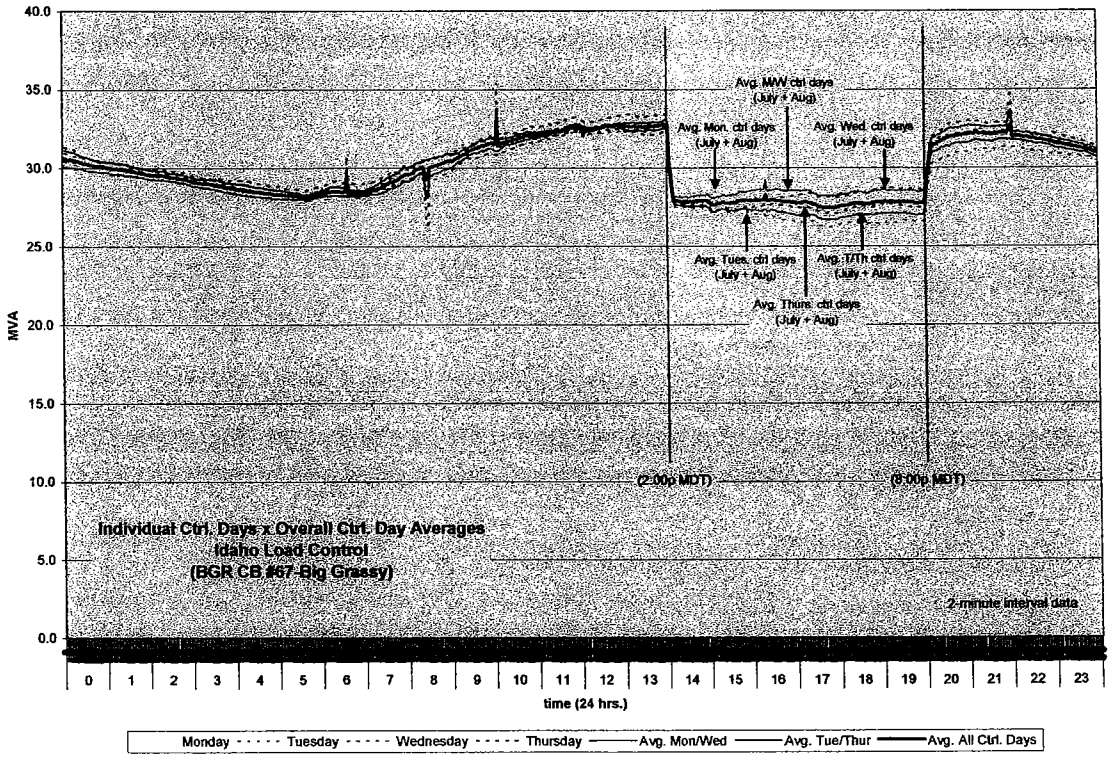


Illustration Four (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Control Average vs. Non-Control Days (CB 67-Big Grassy)*) plots Big Grassy 120-second interval load data by (1) individual non-control day-of-week, (2) average for all non-control days and (3) the average for all control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

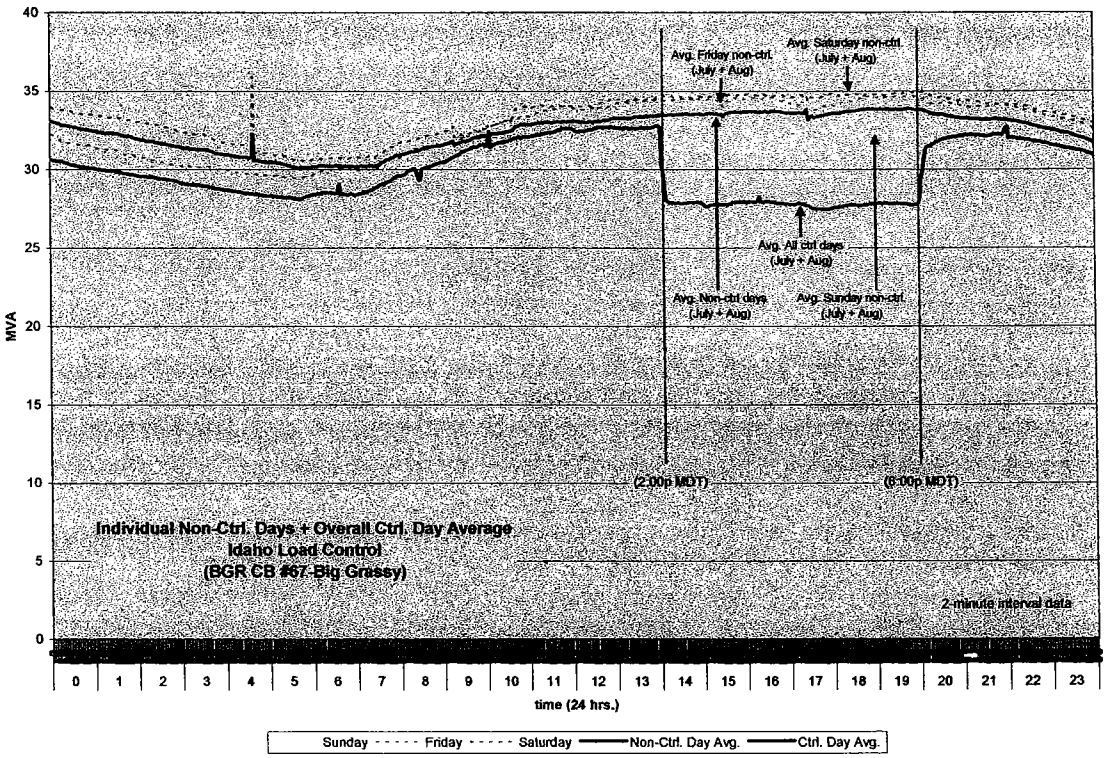
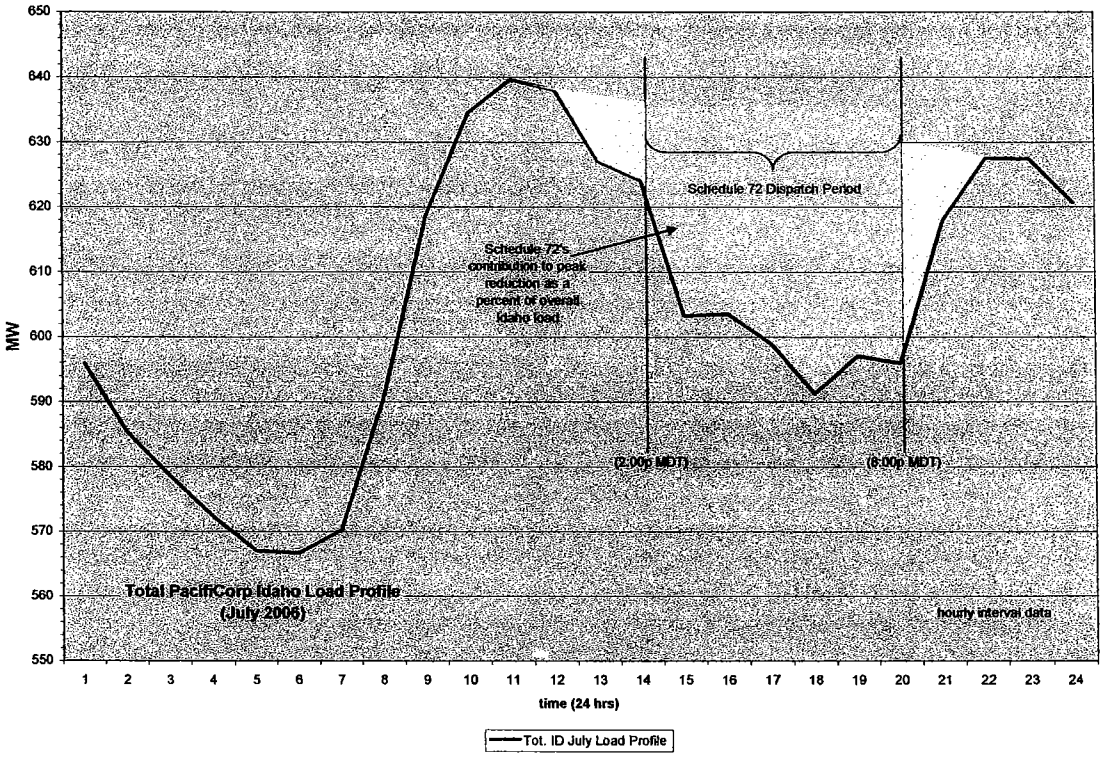


Illustration Five (*Schedule 72 Idaho Irrigation Load Control-Daily Load Curve: Total PacifiCorp Hourly Idaho Load (July) & Estimated Impact of Schedule 72)* plots the total Company average hourly interval load data for the month of July[5]. Also plotted is a 44MW decrement (estimated average avoided 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.

Exhibit No. 302
Case No. PAC-E-07-05
Anthony J. Yankel
1 page

Comparison of Load Research Predicted Interruptions With 2006 Schedule 72 Report

	LRS ID	Strata	kW	Weighting Factor	Weighted kW	Population MW (931 participants)	
M & W							
	00851040	1	9	0.5856	5		hardly operated
	00853060	3	100	0.2009	20		
	00853070	3	150	0.2009	30		
	00853080	3	230	0.2009	46		
	00853130	3	810	0.2009	163		
	00853180	3	165	0.2009	33		
	00853290	3	192	0.2009	39		
	total		1,656	Average	48	44.7	
T & Th							
	00851080	1	59	0.5856	35		
	00852070	2	54	0.1622	9		
	00853010	3	63	0.2009	13		
	00853050	3	87	0.2009	17		
	00853110	3	105	0.2009	21		
	total		368	Average	19	17.6	
data not used							
	00853040	3	92	0.2009	18		not always interrupted
	00853300	3	142	0.2009	29		
No interruptions							
	00851160						
	00852040						
	00853210						very low readings
	00854010						

Exhibit 302

Exhibit No. 303
Case No. PAC-E-07-05
Anthony J. Yankel
1 page

Comparison of Load Research Predicted Interruptions With 2006 Schedule 72 Report

Mondays and Wednesdays

LRS ID	Strata	kW	Weighting Factor	Weighted kW	26-Jun kW	26-Jun wgt. kW	24-Jul kW	24-Jul wgt. kW
M & W								
00851040	1	9	0.5856	5	0	0	0	0
00853060	3	100	0.2009	20	100	20	100	20
00853070	3	155	0.2009	31	155	31	0	0
00853080	3	230	0.2009	46	230	46	230	46
00853130	3	810	0.2009	163	810	163	810	163
00853180	3	165	0.2009	33	165	33	0	0
00853290	3	192	0.2009	39	192	39	192	39
total		1,661	Average	48		47		38

Potential curtailment (kW x 931 customers)	44.8 MW		44.1 MW		35.6 MW
2006 Schedule 72 Report	50.8 MW		37.3 MW		46.7 MW
		Delta	6.8 MW	Delta	-11.1 MW

Exhibit 303

Exhibit No. 304
Case No. PAC-E-07-05
Anthony J. Yankel
1 page

Comparison of Load Research Predicted Interruptions With 2006 Schedule 72 Report
Tuesdays and Thursdays

LRS ID	Strata	kW	Weighting Factor	Weighted kW	22-Aug kW	22-Aug wgt. kW	5-Sep kW	5-Sep wgt. kW
T & Th								
00851080	1	59	0.5856	35	0	0	0	0
00852070	2	54	0.1622	9	54	9	0	0
00853010	3	64	0.2009	13	not curtailed	0	64	13
00853050	3	87	0.2009	17	87	17	0	0
00853110	3	105	0.2009	21	105	21	not curtailed	0
total		369	Average	19		9		3

Potential curtailment (kW x 931 customers)	17.6	MW	8.8	MW	2.4	MW
2006 Schedule 72 Report	50.8	MW	37.3	MW	46.7	MW
			Delta -28.5	MW	Delta -44.3	MW

Exhibit 304

Exhibit No. 305
Case No. PAC-E-07-05
Anthony J. Yankel
Excerpts from "Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources"
22 pages

Final Report – Volume I

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources

Prepared for PacifiCorp

July 11, 2007

In collaboration with Summit Blue Consulting and Nexant, Inc.

quantec *Raising the bar in analytics™*

Investigators:

Hossein Haeri, Ph.D., Lauren Gage, Tina Jayaweera, Ph.D., Collin Elliot, Eli Morris, Rick Ogle, P.E., Tony Larson, Aquila Velonis, Matei Perussi, Allen Lee, Ph.D., and Ann Griffin, Quantec, LLC.

Kevin Cooney, Randy Gunn, Stuart Schare, Adam Knickelbein, and Roger Hill, Summit Blue Consulting

Terry Fry, Mike Boutross, and Pranesh Venugopal, Nexant, Inc.

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Quantec Offices

720 SW Washington, Suite 400
Portland, OR 97205
(503) 228-2992; (503) 228-3696 fax
www.quantecllc.com

1722 14th St., Suite 210
Boulder, CO 80302
(303) 998-0102; (303) 998-1007 fax

28 E. Main St., Suite A
Reedsburg, WI 53959
(608) 524-4844; (608) 524-6361 fax

3445 Grant St.
Eugene, OR 97405
(541) 484-2992; (541) 683-3683 fax

20022 Cove Circle
Huntington Beach, CA 92646
(714) 287-6521

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We are especially grateful to Christopher Kanoff, our project manager, who worked hard to ensure the necessary information was delivered to us on time. Bill Marek made himself available to us when we needed him and helped us develop a better understanding of the complexities of PacifiCorp's Class 1 and Class 3 DSM programs and made it possible to model them properly. Pete Warnken provided much needed support in coordinating the assessment of the potential with the integrated resource planning process.

We thank Jeff Bumgarner, Director of Demand Side Management, and Don Jones, Jr., Energy Efficiency Segment Manager at PacifiCorp, for their support. They offered invaluable insight and direction throughout the course of the study while allowing us to exercise our independent judgment and to maintain our objectivity.

Executive Summary

Overview

For nearly 25 years, PacifiCorp has been actively engaged in the design and delivery of demand-side management (DSM) products and services. Beginning with its management and sponsorship of the Hood River Conservation Project in the early 1980s, PacifiCorp has continued to be an innovator in energy efficiency and has conceived and implemented programs such as Energy FinAnswer, which, in its class, is considered one of the best programs in North America. Over the last 15 years, PacifiCorp has invested approximately $345 million on DSM programs, offsetting nearly 2,700 GWh of energy – the equivalent of nearly 515 MW of capacity annually, assuming a 60% load factor on average.[1] Currently, PacifiCorp operates successful capacity-focused programs for irrigation load curtailment, demand buyback, and air conditioning direct load control, which together helped reduce PacifiCorp's peak loads by 149 MW in 2006. PacifiCorp also has an additional 260 MW available for control under interruptible agreements with a select group of its largest commercial and industrial customers.

Beginning in the early 1990s, PacifiCorp developed biennial integrated resource plans (IRPs) to identify the optimal, least-cost mix of supply and demand-side options to meet its projected long-run resource requirements. This report summarizes the results of an independent study to conduct a comprehensive, multi-sector assessment of the long-run potential for DSM resources in PacifiCorp's Pacific Power (Oregon,[2] Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories to support the PacifiCorp's integrated resource planning process and help further PacifiCorp's active pursuit of DSM resources.

This study's principal goal is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources, comprised of capacity-focused program options (defined throughout this report as Class 1 and Class 3 DSM resources), energy-efficiency products and services (defined as Class 2 DSM resources), and other "supplemental" resources such as solar, combined heat and power, and dispatchable standby generation. The analysis of resource potential in this study are augmented by an examination of the benefits of consumer awareness and education initiatives (Class 4 DSM resources) and an analysis of how future structural changes, such as technological innovation, macroeconomic conditions, and public policy, might affect the findings and conclusions of this study.

The main emphasis of this study has been on resources with sufficient reliability characteristics, which are expected to be technically feasible (technical potential), cost-effective (economic potential), and realistically achievable (achievable potential) during the 20-year planning horizon. For Class 2 DSM (energy-efficiency) resources, the methods used to evaluate the

---

1 Expenditures and savings include PacifiCorp's contributions to the Energy Trust of Oregon and the associated energy savings generated by those funds. All savings and capacity information calculated at generator.

2 Since the Energy Trust of Oregon is responsible for the planning and delivery of Class 2 DSM resources in Oregon, potential for these resources are exclusive of Oregon.

Figure 6. Class 1 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2027)

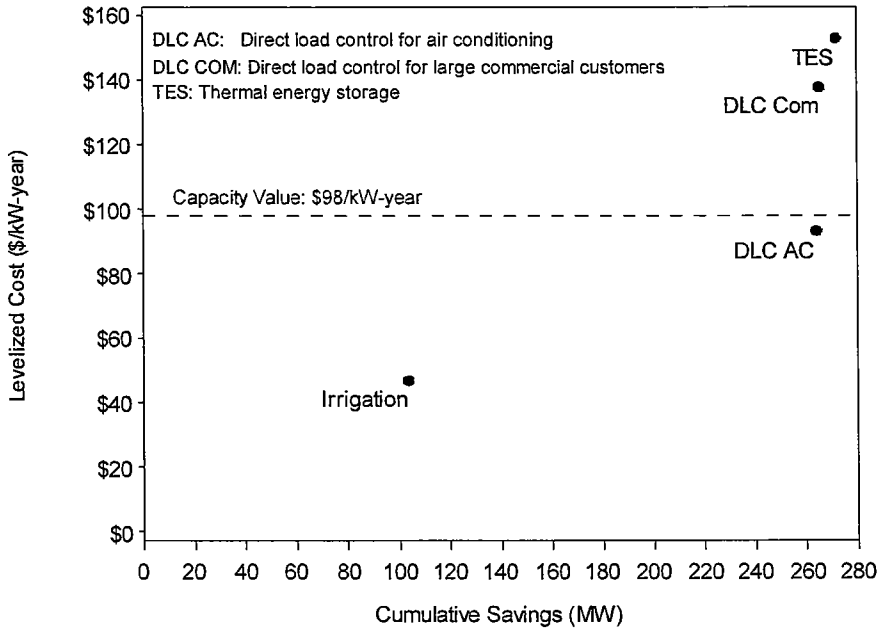
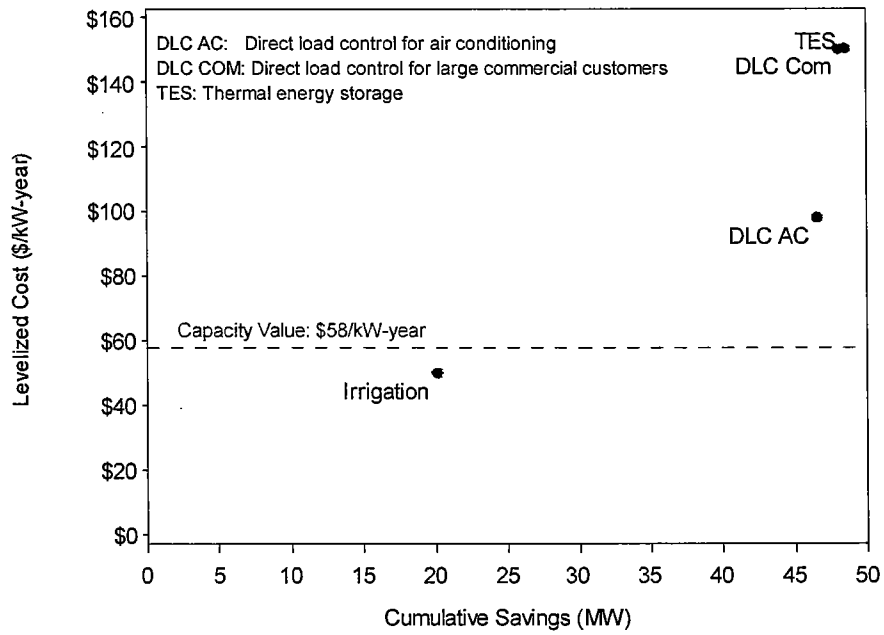


Figure 7. Class 1 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2027)



Irrigation

A program targeting irrigation is an ideal option to reduce summer peak due to the coincidence of irrigation pumping with mid-afternoon summer peaks. PacifiCorp's current irrigation load control program in Idaho is a scheduled control program; customers subscribe in advance for specific days and number of hours when their irrigation systems will be turned off. Load management is executed automatically based on a pre-determined schedule set through a timer device. Although a total of 100 MW of irrigation loads are contracted for management under this control program, less than half are available at any time due to the alternating schedules of program participants. In the Northwest, the Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatched rather than scheduled basis), and Idaho Power has implemented a program similar to PacifiCorp's scheduled control program. In 2007, PacifiCorp began piloting a limited-scope 45 MW dispatchable program in addition to its scheduled control option. Presuming it will be successful, this analysis assumes that, in the future, half of the participants will sign up for the dispatchable control option and half will sign up for the scheduled control option.

Technically, it is assumed all irrigation loads are eligible for this program, excepting half of the Oregon load (which is horizontal pumping and not suitable for this offering). This results in a technical potential of 308 MW (Rocky Mountain Power) and 108 MW (Pacific Power).

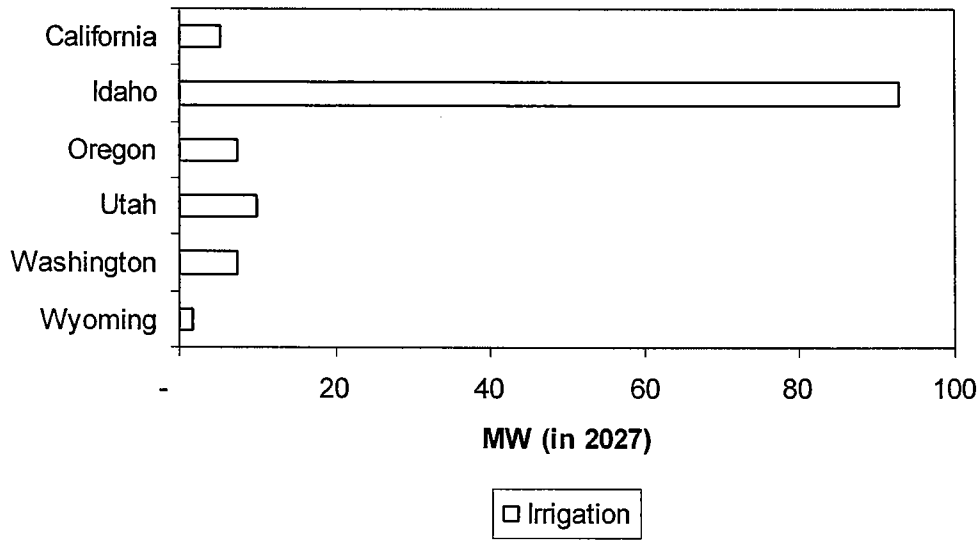
In terms of program participation, both PacifiCorp's and Idaho Power's scheduled control option programs have had solid participation rates: 35% and 25% of eligible load, respectively. This analysis assumes PacifiCorp can increase the participation rate in Idaho to 50% and will reach 25% in other states, where pumps tend to be smaller and loads are distributed across more customers. Assuming one-half of participants are on a scheduled control program, during any one event, only 75% of the load will be available. These factors lead to a market potential estimate of 20 MW for Pacific Power (<1% of 2027 territory peak). For Rocky Mountain Power, 104 MW is available, which includes the 81 MW of expected 2007 achievements (78 MW in Idaho and 3 MW in Utah).

Due to load distribution the majority of this is expected to come from Idaho (93 MW). The PacifiCorp forecasts of irrigation loads expect an overall reduction of approximately 10% over the next 20 years, which is accounted for in the estimate of potential in 2027.

Table 17. Irrigation: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Irrigation	308.3	104.2	21.3%	107.9	20.2	8.1%
Total	**308.3**	**104.2**	**1.3%**	**107.9**	**20.2**	**0.4%**

Figure 14. Irrigation: Market Potential by State (MW in 2027)



Costs for the irrigation program include $400,000 for upfront program costs, $1,000 for installed technology with a life of seven years, $500 for marketing to new customers, and $10/kW for ongoing maintenance and communication systems based on Rocky Mountain Power's experience. Although PacifiCorp currently pays $11/kW-year for incentives (2006 program year), participation level assumptions are based on a higher incentive amount of $20/kW-year in recognition that greater penetration will require higher incentives and the emergence of the dispatchable control option is expected to increase the value of the control to PacifiCorp.

Table 18 displays the resulting levelized costs for the irrigation. With an expected cost of $47/kW-year and $50/kW-year (Rocky Mountain Power and Pacific Power territories, respectively), this program option passes all economic screens. The high achievable scenario assumes a 20% increase in participation and a 50% increase in incentives. With a high achievable cost of $67/kW-year and $70/kW-year (Rocky Mountain Power and Pacific Power, respectively), irrigation in the Rocky Mountain Power territory passes all economic scenarios.

Table 18. Irrigation: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	104	$47	Pass	Pass	Pass
High Achievable	125	$67	Pass	Pass	Pass
Pacific Power					
Expected Achievable	20	$50	---	Pass	Pass
High Achievable	24	$70	---	---	Pass

Table 24 also shows the high achievable scenario, assuming all respondents indicating a "very positive" reaction to the program and one-half of those indicating "somewhat positive" can be convinced to participate, resulting in 29% of customers, or 38 MW for Rocky Mountain Power and 15 MW for the Pacific Power territory. Consistent with all other programs, the high achievable scenario is assumed to have a 50% increase in incentives; so costs rise to $24/kW-year, which again pass all economic screens.

Table 24. Demand Buyback: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	26	$18	Pass	Pass	Pass
High Achievable	38	$24	Pass	Pass	Pass
Pacific Power					
Expected Achievable	10	$18	Pass	Pass	Pass
High Achievable	15	$24	Pass	Pass	Pass

Residential Time of Use Rates

Information on TOU rates was obtained from tariffs from 60 U.S. utilities, promotional materials used by utilities offering new TOU (or TOU with CPP) programs during the past five years, and several interviews with utility staff members.[35] TOU rates have been offered by U.S. utilities since at least the 1970s, but the historic impacts have been quite low. In fact, PacifiCorp ran a TOU pilot in 2002 to 2004, which had extremely low program sign-up (940 residential customers at the end of 2004, with an average of 25% annual attrition), despite an intensive marketing effort.

The TOU rates developed in recent years typically differ from those of the past in several important ways. First, most new TOU rates contain three price tiers as opposed to the two-tier rates common in many long-standing TOU programs, including those offered by PacifiCorp. This allows utilities to set high prices during their highest peak periods and offer exceptionally low off-peak prices overnight when the cost is at its lowest and supply is plentiful. The majority of hours are assigned a "mid-peak" price that is typically a slightly discounted version of the standard rate. Another change is that the duration of the peak period is typically shorter than in the past. Finally, the price differentials between peak and off-peak prices tend to be greater than in the past to encourage load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas newer programs tend to have a differential of greater than 10 cents/kWh. For comparison, PacifiCorp's existing TOU rates offer a price differential of roughly 4.5 cents/kWh to 7.5 cents/kWh, depending on the operating utility and the season.

[35] Includes: Gulf Power, Alabama Power, Ameren, Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, and Teco Energy. Interviews with utility staff: Arizona Public Service, Salt River Project, and Florida Power and Light.

TOU rates are assumed to be available only to the residential customer segments, and the potential is based on the total load rather than individual end uses. The technically feasible portion of the load basis expected to be reduced during peak hours is 5% based on results from California[36] and Puget Sound Energy. The participation rate of the top ten highest-enrolled TOU programs in the country[37] is on average 16%, yet these programs do not represent the experience of all national programs, many of which have participation rates of <1%. If a robust marketing effort is made in conjunction with a TOU rate design that is more than double PacifiCorp's current TOU differential, the expected participation rate is assumed to be 10%.

Table 25 shows there is 107 MW of technical potential and 11 MW of market potential in the Rocky Mountain Power territory. In the Pacific Power territory, there is 78 MW of technical potential and 8 MW of market, both representing less than 1% of 2027 territory peak.

Table 25. Time of Use Rates: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	106.7	10.7	0.5%	77.6	7.8	0.4%
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**106.7**	**10.7**	**0.1%**	**77.6**	**7.8**	**0.2%**

Figure 18 shows Utah has the most potential, with 9 MW, followed by Oregon with nearly 6 MW.

Table 26 displays the per-unit costs, using the assumptions of $400,000 in program development (based on 2002 PGE and PacifiCorp TOU rate program development costs[38]), $125 in new participant costs ($100 per meter and $25 of marketing), with new participant costs reoccurring with annual attrition of 5% (based on electrical turnovers[39]) and a 20-year measure life on meters. Due to low per-customer impacts, the cost per kW-year is $166/kW-year for Rocky Mountain Power territory and $173/kW-year for Pacific Power territory, which pass the economic screens. This finding is consistent with the 2005 evaluation of PacifiCorp's TOU

36 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report," March 16, 2005. See also, Piette, Mary Ann and David S. Watson "Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings," 2006, Lawrence Berkeley National Laboratory. Linkugel, Eric Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 2006.

37 FERC, 2006 and R. Gunn, "North American Demand Response Survey Results" (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

38 Levelized per unit costs are driven primarily by hardware costs. Removal of upfront development reduces the results by $4/kW-year.

39 This is likely a conservative estimate - PacifiCorp 2004 pilot TOU program experienced up to 25% annual attrition.

Final Report – Volume II

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources: Appendices

Prepared for PacifiCorp

July 11, 2007

In Collaboration with Summit Blue Consulting and Nexant, Inc.

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Principal Investigators:

Hossein Haeri, Ph.D., Lauren Gage, Tina Jayaweera, Ph.D., Collin Elliot, Eli Morris, Rick Ogle, P.E., Tony Larson, Aquila Velonis, Matei Perussi, Allen Lee, Ph.D., and Ann Griffin, Quantec, LLC.

Kevin Cooney, Randy Gunn, Stuart Schare, Adam Knickelbein, and Roger Hill, Summit Blue Consulting

Terry Fry, Mike Boutross, and Pranesh Venugopal, Nexant, Inc.

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Quantec Offices

720 SW Washington, Suite 400
Portland, OR 97205
(503) 228-2992; (503) 228-3696 fax
www.quantecllc.com

1722 14th St., Suite 210
Boulder, CO 80302
(303) 998-0102; (303) 998-1007 fax

28 E. Main St., Suite A
Reedsburg, WI 53959
(608) 524-4844; (608) 524-6361 fax

3445 Grant St.
Eugene, OR 97405
(541) 484-2992; (541) 683-3683 fax

20022 Cove Circle
Huntington Beach, CA 92646
(714) 287-6521

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Irrigation

Table B.9. Program Basics

Program Name	Irrigation
Customer Sectors Eligible	Irrigation only
End Uses Eligible for Program	Irrigation Pumping
Customer Size Requirements, if any	All irrigation customers
Summer Load Basis	Top 40 Summer Hours
Winter Load Basis	No Winter

Table B.10. Inputs and Sources not Varying by State or Sector

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Based on changes in electrical service
Annual Administrative Costs (%)	15%	All resource classes assume admin adder of 15%
Technology Cost (per new participant)	$1,000	Technology costs assume $1000 per new participant for installation costs
Marketing Cost (per new participant)	$500	Both Idaho Power and PacifiCorp marketing costs are approximately $500 per new participant
Incentives (annual costs per participating kW)	$20	Idaho Power currently pays $16/kW/year; although Rocky Mountain Power pays $11/kW, high program participation rates and acceptance by customers can be attained only with higher incentives, particularly in diverse geographic regions
Incentives (annual costs per participating kW)	$10	Ongoing Maintenance and Communications (per KW)
Overhead: First Costs (2007$)	$400,000	Standard Program Development Assumption, including necessary internal labor, research and IT/billing system changes
Technical Potential as % of Load Basis	100%	Assumes all loads can be controlled
Program Participation (%)	25%	Idaho Power and PacifiCorp have participation rates of 25% for the scheduled program. PacifiCorp has signed up an additional 45 MW for the DLC option, which totals 35% of the load basis. Assumes that more load is available (50%)
Event Participation (%)	75%	Assumes that one-half of participants will be on scheduled program where participants choose 2 days of each week to schedule reductions during peak times (50% event participation for 50% of program is an average of 75% event participation).
per Customer Impacts (kW)	Varies by Sector	Product of technical potential and average kW of customers greater than 250 kW (PC database of C&I customers)

Residential Time of Use Rates

Table B.20. Program Basics

Program Name	Time Of Use Rates
Customer Sectors Eligible	All Residential Market Segments
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements, if any	Residential
Summer Load Basis	Top 40 Summer Hours
Winter Load Basis	Top 40 Winter Hours

Table B.21. Inputs and Sources not Varying by State or Sector

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Consistent with PacifiCorp electric turnovers. Rate of 3.5% reported by Rosemary Morley of FPL.
Annual Administrative Costs (%)	15%	All resource classes assume admin adder of 15%
Technology Cost (per new participant)	$100	Incremental cost of a TOU meter, APS and FERC 2006
Marketing Cost (per new participant)	$25	APS reported incremental costs of $20-$30 per new participant, including marketing costs and support.
Incentives (annual costs per participant)	$0	Bill savings may accrue for some customers, equating to lost revenues for the utility. This analysis assumes revenue neutrality for the utility.
Overhead: First Costs (2007$)	$400,000	Standard Program Development Assumption, including necessary internal labor, research and IT/billing system changes
Technical Potential as % of Load Basis	5%	California residential pricing programs results from CA SPP , fixed TOU show 5% average peak demand reduced (Charles River Associates, 2005). Results from Puget Sound Energy's cancelled TOU program are similar.
Program Participation (%)	10%	APS has the highest TOU enrollment of any utility in the country at nearly 400,000 participants or 45% of residential customers (Chuck Miessner, APS, 2007; FERC report of 2006). The participation rate of the top 10 highest-enrolled TOU programs in the country is on average 16% (excluding the mandatory rates by PS Oklahoma. Yet, these programs do not represent the experience of all national programs; many TOU programs around the country have participation rates of <1% (but many of these are legacy programs that are not being promoted). Even among the top 10 highest enrollment programs (according to FERC), half have single digit participation rates. If a reasonable effort is made, the reasonable low range might be 2%, which is the lowest participation rate among the top 10 programs, and an expected participation rate of 10%.
Event Participation (%)	100%	There are no "events" with TOU rates. Participation can be viewed as 100%.
per Customer Impacts (kW)		Product of technical potential and average kW of customers based on load basis. Consistent with national studies.