Rocky Mountain Power

Demand Side Management Annual Report - Idaho

Rocky Mountain Power Demand Side Management Team
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Introduction and Executive Summary

Rocky Mountain Power (the "Company") working in partnership with its retail customers and with the approval of the Idaho Public Utilities Commission (the "IPUC"), acquires cost effective demand-side resources as an alternative to the acquisition of supply-side resources. Demand-side resources assist the Company in most efficiently addressing load growth and contribute to the Company's ability to meet system peak requirements. Company demand-side management (DSM) programs provide participating Idaho customers with tools that enable them to reduce or assist in the management of their energy usage, while reducing the overall costs to Rocky Mountain Power's customers. Demand-side resources are a valuable component of Rocky Mountain Power's resource portfolio and are relied upon in resource planning as a least cost alternative to supply – side resources.

Rocky Mountain Power currently offers seven energy efficiency and load control programs in Idaho. Costs associated with these programs as well as the Idaho portion of the Company's contribution to the Northwest Energy Efficiency Alliance are recovered through the Customer Efficiency Services Rate Adjustment (Schedule 191), with the exception of the Load Control Service Credits which are paid to participants of the irrigation load control programs (Schedule 72 and 72A) and are recovered through general rates. The results of Rocky Mountain Power's Idaho demand-side management activities for the reporting period of January 1, 2009 through December 31, 2009 are summarized in Table 1 below.

Table 1

2009 Total Portfolio Performance

System Benefit Revenues Collected	$	(5,010,486)
System Benefit Expenditures (Includes NEEA, Excludes Irrigation Credits)	$	6,432,685
Total Expenditures Including Irrigation Credits	$	13,757,163
MW Under Control (Gross at Generation)		285.2
kWh/Yr Savings (Gross at Generation)		16,362,890

	PTRC	TRC	UCT	RIM	PCT
Portfolio Cost Effectiveness	3.731	3.392	1.831	1.470	9.734

(Note: See notes for Table 2 for explanation of Gross Savings and line loss assumptions)

Participation in the irrigation load control programs increased by approximately 20 percent from 2008 to 2009 providing the Company with 285 megawatts (at generation) of participating load. Overall first year energy savings for 2009 achieved through energy efficiency programs, increased by more than 40 percent while Customer Efficiency Services expenditures increased 35 percent.

At the end of 2009, the Customer Efficiency Services balancing account had an unfunded balance of $ 2,238,820.27.

In October 2009, the Company initiated process and impact evaluations for several Idaho programs including the Home Energy Savings, Refrigerator Recycling, Energy FinAnswer, FinAnswer Express and Agricultural Energy Services programs for program years 2006 to 2008. The evaluation work is being completed by an independent evaluator (The Cadmus Group) which was selected via a competitive bidding process. Draft and final reports for the evaluations are expected to be completed in the second quarter of 2010, with the exception of the Agricultural Energy Services program, which will be completed in the third quarter.

Overall, Rocky Mountain Power's demand side management portfolio was cost effective under all five tests based on 2009 results. In addition, all demand side management programs were cost effective based on the Utility Cost and the Total Resource Cost tests, with the exception of the Agricultural Energy Services program. Factors contributing to the marginal Total Resource Cost test results for this program for 2009 are outlined on pages 26 - 28. On an individual program basis, only the Irrigation Load Control programs satisfied the Rate Impact Test.

For the period January 1, 2009 through December 31, 2009, demand side management acquisitions for all programs produced an estimated $17.1 million in net benefits over the life of the savings on a Total Resource Cost basis.

2009 Performance and Activity

Program and Sector level results for 2009 are provided on the following table[1]. Program Schedules are noted in parenthesis in the table.

Table 2

Idaho DSM Annual Results for 2009

Program	Units	kW/Yr (at site)	kW/Yr Savings (at generator)	Program Expenditures
Irrigation Load Control (72 and 72A)	2,050	258,355	285,203	$ 3,816,417.26
Total Load Control	**2,050**	**258,355**	**285,203**	**$ 3,816,417.26**
Program	**Units**	**kWh/Yr Savings (at site)**	**kWh/Yr Savings (at generator)**	**Program Expenditures**
Low Income Weatherization (21)	112	194,919	217,118	$ 197,819.17
Refrigerator Recycling (117)	725	957,819	1,066,905	$ 108,125.50
Home Energy Savings (118)	4,610	1,349,279	1,502,948	$ 593,563.82
Total Residential	**5,447**	**2,502,017**	**2,786,971**	**$ 899,508.49**
Energy FinAnswer (125)	4	189,345	209,601	$ 49,790.48
FinAnswer Express (115)	33	644,669	713,636	$ 189,925.40
Total Commercial	**37**	**834,014**	**923,237**	**$ 239,715.88**
Energy FinAnswer (125)	4	1,305,202	1,440,839	$ 308,636.28
FinAnswer Express (115)	23	193,726	213,858	$ 73,978.69
Agricultural Energy Services (155)	225	3,994,349	4,409,442	$ 807,238.30
Total Industrial	**252**	**5,493,277**	**6,064,138**	**$ 1,189,853.27**
Market Transformation				
Northwest Energy Efficiency Alliance		**5,914,896**	**6,588,544**	**$ 287,190.31**
Total Energy Efficiency		**14,744,204**	**16,362,890**	**$ 2,616,267.95**

Total System benefit Expenditures - All Programs	**$ 6,432,685.21**
Load Control Participation Credits 2009	$ 7,324,477.43
Total Idaho Program Expenditures	**$ 13,757,162.64**

[1] Savings values in this table are shown prior to any net-to-gross adjustment. The values at generation include line losses between the customer site and the generation source. The Company's line losses by sector are 11.389 percent for residential, 10.698 percent for commercial and 10.392 percent for industrial. These values are based on the Company's 2001 Transmission and Distribution Loss Study by Management Applications Consulting published in June 2004.

Major Trends and Activities:

In 2009, the Company realized substantial increases in demand side management acquisitions in the majority of sectors and programs. Overall, first-year energy savings from energy efficiency programs increased more than 40 percent compared to 2008, while the Irrigation Load Control Program delivered 20 percent more participating kW for management in 2009. At a sector lever, the Residential Sector realized 23 percent higher savings on a kWh/year basis compared to 2008, and the combined business and agricultural sectors delivered 78 percent more kWh/year savings than in 2008.

Expenditures related to program delivery increased in 2009 as compared to 2008. Overall expenditures for Energy Efficiency and Load Management programs (excluding load management participation credits) increased by 35 percent compared to 2008. When Irrigation Load Control participation credits are included, expenditures increased by 28 percent in 2009 compared to 2008. At a sector level, the Residential sector expenditures increased by 9 percent, business and agricultural sectors increased by 157 percent and Load Control increased by 22 percent.

Cost Effectiveness:

Consistent with the requirements outlined in Memorandum of Understanding signed by the Company and Idaho Commission Staff, the Company provides cost effectiveness results utilizing five Cost Effectiveness Tests;

1. PacifiCorp Resource Cost Test (PTRC) which includes a 10 percent additional benefit for demand side resources. This is consistent with Northwest Power Planning and Conservation Act.
2. Total Resource Cost Test (TRC)
3. Utility Cost Test (UCT)
4. Ratepayer Impact Test (RIM)
5. Participant Cost Test – (PCT)

The results for each test are provided at several levels:

1. Overall Portfolio level, consolidation of all Company delivered programs
2. Load Control and Energy Efficiency program portfolio
3. Residential and Non-Residential energy efficiency program portfolio
4. Individual Program

All portfolios and programs had a UCT benefit/cost ratio of more than 1.0 indicating that for each dollar invested the benefits were greater than the required investment. Overall, the portfolio generated $17.1 million in Net Benefits (on a TRC basis) and was cost effective across all five Cost Effectiveness Tests at the portfolio, segment and program level, with the exception of the Agricultural Energy Services program noted above.

Results of the Cost Effectiveness tests are included in the summary overview for each program. Further details including key inputs and assumptions for each of the cost effectiveness tests are provided in the cost effectiveness section of this report.

Program Evaluation

On October 5, 2009 Rocky Mountain Power participated in informal discussions with the Idaho Commission Staff, Avista and Idaho Power regarding guidelines for demand side management program cost effectiveness calculation, program evaluations, demand side management reporting requirements and determination of prudency. In the following weeks, Commission Staff and these investor owned utilities worked jointly to develop a Memorandum of Understanding (MOU) that outlines expectations for program evaluations, calculations of cost effectiveness and requirements for annual reporting of demand side management program activities in support of a finding of prudency for demand side management expenditures. The MOU was signed by Rocky Mountain Power, Avista, Idaho Power and the Commission Staff and was filed on January 25th, 2010[2].

As part of the MOU, Rocky Mountain Power agreed to provide a timeline for when evaluations would be completed for each program offered in the state. The Program Evaluation Timeline (Table 3 below) provides an outline of evaluations for each program in Rocky Mountain Power's demand side management portfolio.

Table 3

Program Evaluation Timeline

Program	Evaluation Type	Status	Anticipated Year Complete	Program Year(s) Evaluated	Evaluator
Home Energy Savings	Process and Impact	In Process	2010	2006 - 2008	The Cadmus Group
See Ya Later Refrigerator	Process and Impact	In Process	2010	2006 - 2008	The Cadmus Group
Low Income Weatherization	Impact	Planned	2010	2007 - 2009	To Be Determined
Energy FinAnswer	Process and Impact	In Process	2010	2008	The Cadmus Group
FinAnswer Express	Process and Impact	In Process	2010	2006 - 2008	The Cadmus Group
Irrigation Energy Savers	Process and Impact	In Process	2010	2006 - 2008	The Cadmus Group
Irrigation Load Control	Impact	Complete	Annual	Annual	Company Evaluated & Reported

[2] The MOU was entered by Idaho Power as part of a Stipulation in Case IPC E 09-09, filed on January 25, 2010.

In October, 2009, the Company initiated third-party independent process and impact evaluations for the Home Energy Savings, See ya later refrigerator, Energy FinAnswer, FinAnswer Express and Agricultural Energy Services programs for program years 2006 – 2008. The draft results of these evaluations are expected to be available during the second and third quarters of 2010. Findings from these evaluations will be key inputs to on-going program design and modification as well as inputs to future cost effectiveness determinations.

As available, Rocky Mountain Power will provide copies of the draft and final evaluation reports to the Commission staff as well as post them on the Company web site at http://www.pacificorp.com/es/dsm.html for public viewing.

No process, impact or market impact evaluations were completed on Rocky Mountain Power programs in Idaho during 2009 as part of the development of this report.

In compliance with the MOU, each of the program sections in this report provides a description of in-process or planned program evaluations. Any process or program changes (whether the result of an evaluation or not) will be included in the narrative section of each program. The specific assumptions and changes to cost effectiveness inputs (as outlined in the MOU) will be included in the cost effectiveness appendix (Appendix 1 of this report).

Plans for Next Year:

The Company filed a request with the Commission on February 25, 2010 to increase the level of the Tariff Rider (Schedule 191) to better match collections with program expenditures and to reduce the unfunded balance in the Schedule 191 balancing account. The unfunded balance as of December 31, 2009 was approximately $2.2 million. The request seeks to increase the collection rate from 3.72 percent to 5.85 percent.

The Company expects to complete the process and impact evaluations as outlined in the previous section of this report during the second quarter of 2010 (with the exception of the Agricultural Energy Services program evaluation which will be complete in the third quarter). Evaluation results for these programs will be reflected in an update during the third quarter of 2010 and in the Idaho 2010 Demand Side Management Annual Report.

During 2010, the Company plans to make modifications to the Home Energy Savings program including lighting, appliances, HVAC and weatherization or shell measures intended to adjust to changing market conditions and further improve program performance.

The Company will be filing changes to the FinAnswer Express program to reflect changes in standards for lighting, motors and HVAC equipment.

Finally, the Company is contracting for an update of the *2007 Assessment of Long-Term System Wide Potential for Demand Side and Supplemental Resources* during 2010. The update will be used to inform the Company in the development of the 2011 Integrated Resource Plan, demand side program management and valuation.

Engagement with Commission and Interested Parties

The Company made several filings and participated in informal proceedings with the Commission regarding demand side management during 2009. The dates of the filings and activities and descriptions are included below.

February 11, 2009 – Advice 09-01 Rate Schedule 72A (Irrigation Load Control)
The Company proposed changes to the Irrigation Load Control program tariff. The changes included clarification for pre-season internet access for communications, revised contract language related to payment options, calculation of average demand when a customer has less than two years of usage history, revision of notification dates and clarification of pricing for liquidated damages.
The request was approved on May 7, 2009 with an effective date of June 1, 2009.

March 18, 2009 – Rocky Mountain Power Demand Side Management 2008 Annual Report for the Idaho Jurisdiction
Rocky Mountain Power provided its 2008 Annual Demand Side Management report to the Idaho Commission for review.

October 5, 2009 – Informal Demand Side Management Workshop – Evaluation and Cost Effectiveness
Rocky Mountain Power participated in an informal workshop with representatives from the Idaho Commission Staff as well as Idaho Power and Avista. Please see the description of the activities under the Program Evaluation heading in the previous section of this report.

October 6, 2009 - Meeting with the Idaho Irrigation Pumper's Association (IIPA)
Rocky Mountain Power met with IIPA representatives to discuss the Dispatchable Irrigation Load Control Credit Rider program, Schedule 72A. Commission Order No. 30482 approved the load control credit level to participants for the 2008 and 2009 irrigation seasons. Parties discussed the results of the program, what worked and what revisions could improve the program. At that meeting an agreement was reached to continue with the existing load control credit level, remove the month of September from the program and revise the dispatch hours.

October 28, 2009 – Advice 09-05 Rate Schedule 72A (Dispatchable Irrigation Load Control Credit Rider)
Based on the agreement reached with the IIPA in the October 6, 2009 meeting the Company filed Tariff Advice 09-05 with the Commission requesting authority to modify Schedule 72A. The modifications included extending the current load control service credit schedule through the 2012 irrigation season, shortening the program season to June through August and extending the dispatch period to 11:00 AM to 7:00 PM Mountain Daylight Savings time. The Commission approved the Tariff Advice 09-05 as filed with December 31, 2009 effective date.

2009 Idaho Irrigation Load Control Quantitative Review
Rocky Mountain Power provides its annual report of the results and activities associated with the Irrigation Load Control programs offered under Schedule 72 and 72A as a separate report. The reporting period for the current report is October 1, 2008 to September 30, 2009. Starting in 2010, the Company intends to report on a calendar year basis and combine that information in this Demand Side Management Annual Report. Please see the Irrigation Load Control section of this report for more details about changes in the reporting period. The *2009 Idaho Irrigation Load Control Quantitative Review* is included with this report as Appendix 2.

Idaho Strategic Energy Alliance (Formerly the 25 x 25 Task Force)
Rocky Mountain Power participates in the Idaho Strategic Energy Alliance with representation on the Alliance Board of Directors and participation on the Energy Efficiency Task Force. The Alliance published a set of recommendations developed by the Energy Efficiency Task Force on October 8, 2009. Among the recommendations was to provide support to the K-12 Schools Facilities Energy Efficiency activities. The Company anticipates supporting energy efficiency analysis activities during 2010. For further details on the Company's participation, please see the Plans for Next Year portion of the Energy FinAnswer program description.
For more details on the Idaho Strategic Energy Alliance, please go to the Alliance website at http://www.energy.idaho.gov/energyalliance/ .

Load Management Programs and Activity

Irrigation Load Control (Schedule 72 and 72A)

This program is marketed as the Irrigation Load Control program (Schedules 72 & 72A) and is offered to Idaho irrigation customers receiving retail electric service on Schedule 10. Participants agree to allow for the curtailment of their electricity usage as prescribed in Schedules 72 and 72A in exchange for the receipt of participation credits. A report specific to the 2009 irrigation season for this program is attached to this report as Appendix 2 and covers the period from October 1, 2008 through September 30, 2009[3]. Savings (MW and participation) information in Tables 2, 4 and 26 included in this report were taken from that report. The costs included in Tables 2, 4 and 26 reflect actual calendar year 2009 expenditures. Please see Reporting Period Changes below.

Summary program performance, expenditures, participation and cost effectiveness results are provided in the following table.

Table 4[4]

2009 Irrigation Load Control Program Performance	
MW Under Control (Gross at Gen)	285.2
Expenditures - Total	$ 11,140,895
Participation Credits	$ 7,324,477
Program Operations Expense	$ 3,816,417
Participation (Customers)	938
Participation (Sites)	2,050

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	5.808	5.280	1.813	1.813	NA

Additional information on the irrigation load control program is available in the 2009 seasonal report *2009 Idaho Irrigation Load Control Quantitative Review* dated November 14, 2009. While field and program management costs for the program are recovered through Schedule 191, Customer Efficiency Services Rate Adjustment, the program's customer participation credits are recovered through general rates. Enrollment and site installations for the 2010 season are currently underway.

[3] Report is dated November 14, 2009
[4] Participation results from *2009 ID Irrigation Quantitative Review*, Tables one and twelve.

Major Trends and Activities

As previously mentioned, the Company proposed modifications to Schedule 72A in Advice 09-01, dated February 11, 2009. The primary changes were revisions to tariff language related to communications availability, estimates when usage history is inadequate and clarification of pricing for liquidated damages. The request was approved on May 7, 2009 with an effective date of June 1, 2009.

Additional modifications were proposed in Advice 09-05, including extending the current load control service credit schedule through the 2012 irrigation season, shortening the program season to June through August and extending the dispatch period to 11:00 AM to 7:00 PM Mountain Daylight Savings time. The Commission approved Advice 09-05 as filed with a December 31, 2009 effective date.

Reporting Period Changes

Please note that the costs included in this Demand Side Management Annual Report reflect cost associated with the Calendar Year 2009, while the costs included in *2009 Idaho Irrigation Load Control Quantitative Review* reflect costs for the Seasonal Report that runs from October 1 to September 30. Operational results and savings are consistent between reports because the load control season occurs during June through August of each year.

Therefore, results included in this Annual Report reflect the operations/savings and costs for the Calendar year 2009. Cost Effectiveness was reevaluated to reflect the difference in period costs and details are included in the Cost Effectiveness section of this report.

Program costs reflected in this annual report are $460,284 higher than those reflected in the *2009 Irrigation Load Control Quantitative Review*, while the operational results and associated savings and benefits are identical between reports. As a result, the cost effectiveness test results are slightly lower in this annual report than those reported in the *2009 Idaho Irrigation Load Control Quantitative Review*.

For consistency and to improve reporting efficiency, beginning in Calendar Year 2010, the Idaho Irrigation Load Control Report (or *Idaho Irrigation Load Control Quantitative Review*) will reflect calendar year results and costs, and it will be included with the filing of this Demand Side Management Annual Report.

Program Evaluation

Rocky Mountain Power has provided an annual report (or *ID Irrigation Quantitative Review*) of the activities and results of the Idaho Irrigation Load Control Program to the Idaho Commission each year since the program started in 2003. These results reflect the measured actual dispatch and impact on the system. The annual reporting approach utilizes a work plan similar to those used by third party evaluation firms and serves as an annual program evaluation.

Plans for Next Year

Program expenditures are expected to increase in 2010 above the 2009 levels. The increase will provide further resources to support the program. Historically, program delivery has been heavily supported by Company resources, but that level of support is no longer sustainable due to the increased size and complexity of the program. The Company expects to engage further support from external vendors for on-going delivery of the program to address these issues as well as to maintain the reliability of the resource.

The growth in the size of the load control program over the past few years is beginning to pose some new challenges as we plan for the future. Specifically, the Company is experiencing voltage issues on circuits where irrigation is the predominate load. The Company is currently evaluating several potential solutions to the issue and will provide additional information as it becomes available.

Residential Energy Efficiency Programs and Activity

Home Energy Savings Program (Schedule 118)

The Home Energy Savings program (Schedule 118) provides a broad framework to deliver incentives for more efficient products and services installed or received by Idaho customers in new or existing homes, multi-family housing units or manufactured homes. The program is delivered through, Portland Energy Conservation, Inc. (PECI), a third party administrator hired by the Company. Program information is available to the public at the program's web site at www.homeenergysavings.net/idaho/home and can also be accessed through www.rockymtnpower.net/Article/Article45165.html, the Company's Idaho energy efficiency program website.

Eligible program measures include: washing machines, refrigerators, water heaters, dishwashers, lighting (both compact florescent lamps (CFLs) and fixtures), cooling equipment and services, ceiling, wall and attic insulation, windows and miscellaneous equipment such as ceiling fans. Incentives are provided to customers through two methods: (1) post-purchase application process with incentives paid directly to participating customers, and (2) mid-market (i.e., retailers and manufacturers) buy-downs, for delivery of CFL incentives. Mid-market buy-downs result in lower retail prices for customers at point-of-purchase and involve no direct customer application process.

Program results for 2009 are provided in the Table below.

Table 5

2009 Home Energy Savings Program Performance

kWh/Yr Savings 2009 (Gross - At Gen)	1,502,948
Expenditures	$ 593,564
Incentives Paid	$ 354,913

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	1.454	1.322	1.731	0.722	6.453
Levelized Cost ($/kWh)	0.062	0.062	0.047		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000046				

Details of 2009 measure level participation and savings are provided on the following table.

Table 6

2009 Home Energy Savings Measure Performance

Home Energy Savings Measures	Unit Measurement	# of Units	Participants	kWh/Yr Savings (Gross - At Site)
Clothes Washer-Tier One	Units	120	120	26,259
Clothes Washer-Tier Two	Units	913	913	220,435
Dishwasher	Units	320	320	9,688
Electric Water Heater	Units	93	93	8,435
Refrigerator	Units	310	310	30,225
Insulation: Attic	Sq Feet	362,591	275	379,517
Insulation: Floor	Sq Feet	16,009	16	8,586
Insulation: Wall	Sq Feet	19,834	23	25,047
Windows	Sq Feet	12,685	114	18,245
CAC/HP Tune up	Projects	98	98	4,032
Evaportative Cooler	Units	2	2	650
Central A/C Equipment	Units	3	3	288
Duct Sealing - Electric	Projects	1	1	2,152
Duct Sealing - Gas	Projects	20	20	800
Heat Pump Conversion	Units	2	2	6,294
Heat Pump Upgrade	Units	3	3	2,433
Proper CAC Install	Projects	1	1	23
Proper CAC Sizing	Projects	1	1	67
Ceiling Fans	Units	9	4	963
Fixtures	Units	46	26	4,232
CFLs	Bulbs	22,666	2,266	600,908
Totals		**435,727**	**4,611**	**1,349,280**
kWh/Yr Savings at Generation				1,502,950

(Note: CFL Participation is assumed at 10 CFLs per participant.)

Major Trends and Activities:

The Home Energy Efficiency Incentive program savings in 2009 more than doubled as compared to 2008, while the expenditures increased approximately 20 percent versus 2008. Reasons for the 2008 reduced program performance were explained in the 2008 annual report and included the misalignment of specialty bulb pricing with the regional offering. This situation was remedied in 2009 and helped contribute to a four-fold increase in lighting activity and savings when compared with 2008 results.

The availability of federal tax credits and media coverage surrounding federal stimulus funding began increasing the overall awareness and interest in providing for energy efficiency opportunities in homes. Contractors and retailers in turn have developed marketing messages and sales materials that feature the availability of the federal tax credit increased customer contact. Use of the tax credit as a sales tool has been especially prominent in the window replacement and home insulation markets. The addition of incentives for heat pumps in 2008 increased overall activity in the HVAC market that has carried over into 2009 program results.

Weatherization activity has increased as the result of the slowdown in the new construction markets, increasing competition among contractors now focusing on the retrofit market. The impact has been threefold; 1) reduction in installed costs of weatherization services; 2) near “free” deal for customers; and 3) an increase of insulation projects. This trend has been further accelerated by the availability of the federal tax credit. The activity accelerated in the last two months of 2009 and to better align program incentives and intended program design with current market conditions, the Company utilized the notice provisions of Schedule 118 on February 3, 2010 to inform customers and contractors that insulation incentives will change effective March 20, 2010.

Cost Effectiveness

The program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1provides detailed inputs used in the cost effectiveness analysis of this program.

Program Evaluation

Please see the discussion under the Program Evaluation heading in the 2009 Performance and Activities section of this report for evaluation activities related to this program.

Plans for Next Year

During 2010, the Company plans to make modifications to the Home Energy Savings program including lighting, appliances, HVAC and weatherization or shell measures. Changes for insulation, including incentive levels adjustments are underway using the procedure outlined in Idaho Schedule 118 with changes effective on March 20, 2010.

“See ya later, refrigerator” (Schedule 117)

The Idaho Refrigerator Recycling Program (Schedule 117) is available to Idaho residential customers through a Company contract with a third-party program administrator, JACO Environmental Services. Older refrigerators and freezers which are less efficient, yet operational, are taken out of use permanently and recycled in an environmentally responsible manner. The program’s objective is to permanently retire these older and less efficient refrigerators and freezers from the market and recycle the units in order to avoid their re-entry or resale on the secondary appliance market. To participate customers call a 1-800 number to schedule a pick-up. Program awareness is generated through mass media advertising channels as well as Company channel communications such as the program’s web site, bill stuffers, and customer newsletters. In addition to free pick-up and a nominal cash incentive, participants receive an energy efficiency packet consisting of ENERGY STAR®-certified compact fluorescent light bulbs, a refrigerator/freezer thermometer, and energy education materials.

Program results for 2009 are provided in the table below.

Table 7

2009 "See ya later, refrigerator" Program Performance

kWh Savings 2009 (Gross - At Gen)	1,066,905
Expenditures	$ 108,126
Incentives Paid	$ 21,750

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	2.246	2.042	1.631	0.565	NA
Levelized Cost ($/kWh)	0.0317	0.0317	0.0317		
Lifecycle Revenue Impact ($/kWh)	$ 0.000004662				

Details of 2009 measure level participation and savings are provided on the following table.

Table 8

"See ya later, refrigerator" 2009 Results

Refrigerator Recycling Measure	Unit Count	Per Unit Savings (kWh/Yr)	Gross Savings (kWh/Yr)
Refrigerator	566	1,149	650,334
Freezer	159	1,590	252,810
Total Units Recycled	**725**		**903,144**
Energy Savings Kits	675	81	54,675
		Total (At Site)	**957,819**
		Total (At Generation)	**1,066,905**

Total Expenditures	$	108,126
Total Cash Incentives	$	21,750

Major Trends and Activities

Participation for 2009 was slightly higher than in 2008 however the level of participation has been affected by the economic slowdown.

In terms of the impact of the program on the environment, processing the 725 units resulted in the recycling of more than 90 thousand pounds of metal, 18 thousand pounds of plastics, half a ton of tempered glass and the capture, recovery or destruction of more than 875 lbs of ozone depleting Chlorofluorocarbons (CFC)and Hydrofluorocarbons (HFC), commonly used in refrigerants. The Carbon Dioxide (CO_2) and Equivalent carbon dioxide (CO_2e) avoided from the atmosphere was equal to 7.250 tons.

Cost Effectiveness

The 2009 See ya later, refrigerator program was cost effective from both a UCT and TRC perspective. There are no participant costs, so results of that test were not calculated. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program. .

Program Evaluation

Please see the discussion under the Program Evaluation heading in the 2009 Performance and Activities section of this report for evaluation activities related to this program.

Plans for Next Year

JACO Environmental anticipates an increase in participation as economic conditions improve.

Several new program design features will help add volume to the program starting in spring of 2010. The American Recovery and Reinvestment Act (ARRA) stimulus funding program will allow purchasers of new Energy Star refrigerators to qualify for rebates at local appliance retail stores while receiving the $30 incentive for turning in the older working appliances they are replacing. JACO will be working with Sears, Best Buy, Lowe's & other appliance retailers in Idaho to allow customers to have the new units delivered and the old units picked up at the same time. This will mean home owners need only one appointment. JACO will continue its retail participation after the ARRA program has ended to make it more convenient for customers to participate in the "See ya later, refrigerator" program.

Low Income Weatherization (Schedule 21)

The Low Income Weatherization Services program (Schedule 21) is available through a partnership with Eastern Idaho Community Action Partnership (EICAP) in Idaho Falls and Southeastern Idaho Community Action Agency (SEICAA) in Pocatello. These partnerships allow for leveraging of Company funding with federal grants available to EICAP and SEICAA, increasing the number of homes served. Rocky Mountain Power's funding provides rebates that cover 75 percent of the cost of approved energy efficiency measures.

Income eligible households receive energy efficiency services at no cost. Participants can be either homeowners or renters residing in single-family homes, manufactured homes and apartments.

Table 5 summarizes the program results for 2009. The reported energy savings is based on measured savings documented in an analysis dated August 30, 2006 completed by Quantec/Cadmus. The expenditures of $197,819 are those paid by Rocky Mountain Power. Funds received by the agency from other sources (state or federal funding) are not included.

Rocky Mountain Power's program provided funding towards the weatherization of 112 qualifying homes in 2009 with an average program cost per home of $1,766.

Table 9

Low Income Weatherization Performance - Idaho		
kWh/Yr Savings (at Site)		194,919
kWh/Yr Savings (at Gen)		217,118
Expenditures - Total	$	197,819
Participation - Total # of Completed/Treated Homes		112
Number of Homes Receiving Specific Measures		
Ceiling Insulation		34
Floor Insulation		20
Wall Insulation		3
Replacement Windows		38
Storm Windows		6
Duct Insulation/Sealing		9
Insulated Doors		37
Attic Ventilation		23
Infiltration		50
Water Pipe Insulation and Sealing		54
Water Heater Repair/Replacement		8
Faucet Aerators		-
Showerheads		-
Programmable Thermostats		19
Furnace Repair/Tune-up		3
Furnace Replacement		-
Compact Fluorescent Light bulbs		111
Replacement Refrigerators		8
Home Repairs		-
Health and Safety		32

Plans for Next Year

An updated impact and process evaluation is anticipated to be completed during 2010.

Non- Residential Energy Efficiency Programs and Activity

Energy FinAnswer (Schedule 125)

The Energy FinAnswer program (Schedule 125) was approved in Idaho effective May 1, 2008. This program was initially included in the Company's 2005 filing and later removed from the filing to better align the demand side management program expenditures with available funding under the original collection rate approved by the Commission. 2009 represents the first full year of program operation in the Idaho market.

The program provides Company-funded energy engineering, incentives of $0.12 per kWh of first year energy savings and $50 per kW of average monthly demand savings up to a cap of 50 percent of the approved project cost. The program is designed to target comprehensive projects requiring project specific energy savings analysis and operates as a complement to the more streamlined FinAnswer Express program. In addition to customer incentives, the program provides design team honorariums (a finder fee for new projects) and design team incentives for new construction projects exceeding current Idaho energy code by at least 10 percent.

The summary program results are provided in the table below.

Table 10

2009 Energy FinAnswer Program Performance

kWh/Yr Savings 2009 (Gross - At Gen)	1,650,440
Expenditures	$ 358,427
Incentives Paid	$ 151,234

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	2.104	1.913	2.883	0.987	5.012
Levelized Cost ($/kWh)	0.0378	0.0378	0.0251		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000002336				

Details of 2009 savings by type of measure are provided on the following table

Table 11

Energy FinAnswer kWh/Yr Savings (at site) by Measure Type

Compressed Air	634,436	42%
Process	420,996	28%
Lighting	229,128	15%
HVAC	103,626	7%
Refrigeration	60,914	4%
Pumping	45,447	3%
	1,494,547	

Major Trends and Activities

A total of eight Energy FinAnswer projects were completed in 2009 compared to five in 2008. Program specific energy savings increased more than three-times from 2008 to 2009.
The Company continues to market the program through its Customer and Community Managers and network of trade allies in concert with the FinAnswer Express program. The pipeline of forecasted projects is increasing when compared to 2008.

Cost Effectiveness

The 2009 Energy FinAnswer program was cost effective from a TRC, UCT, and PCT perspective. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program.

Program Evaluation

Please see the discussion under the Program Evaluation heading in the 2009 Performance and Activities section of this report for evaluation activities related to this program.

Plans for Next Year

Continue to monitor actual and forecasted participation and assess the potential impacts of program modifications similar to those implemented in other markets.

As recommended by the Idaho Strategic Energy Alliance, the Idaho State Energy Program (SEP) initiated an energy assessment of all of the K-12 schools in the state (700+) during 2009. While the analysis work is being performed by Idaho SEP funded contractors, school districts served by Rocky Mountain Power have asked the Company for some additional analysis services as they prepare to prioritize their projects. The preliminary school analysis phase will likely be completed during 2010 and the Company expects some customers will utilize available utility incentives to assist with the funding of their most promising projects.

FinAnswer Express (Schedule 115)

The FinAnswer Express program (Schedule 115) is available to Idaho business customers excluding those served on Schedule 10, who are eligible for program services through the Agricultural Efficiency Services program. The program is designed to help customers improve the efficiency of their new or replacement lighting, motors, and other equipment purchases by providing prescriptive or pre-defined incentives for the most common efficiency measures. The program is designed to operate in conjunction with the Energy FinAnswer program. Although incentives available vary, the program provides incentives for both new construction and retrofit projects.

The program is primarily marketed through local trade allies who receive support from Company provided sales and training team. Twenty-eight trade allies have signed Company program participation agreements as of the end of 2009

The summary program results are provided in the table below.

Table 12

2009 FinAnswer Express Program Performance

kWh/Yr Savings 2009 (Gross - At Gen)	927,494
Expenditures	$ 263,904
Incentives Paid	$ 81,320

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	1.600	1.455	2.325	0.741	4.192
Levelized Cost ($/kWh)	0.0577	0.0577	0.0361		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000042419				

Details of 2009 savings by type of measure are provided on the following table.

Table 13

FinAnswer Express kWh/Yr Savings (at site) by Measure Type

Lighting	748,891	89%
Non-Lighting	89,504	11%
	838,395	

Major Trends and Activities

2009 savings were lower than in 2008 primarily as the result of the availability of the Energy FinAnswer program in 2009. Prior to May 2008, FinAnswer Express was the sole program available to Rocky Mountain Power business (non-irrigation) customers. On a combined basis, 2009 kWh savings from Energy FinAnswer and FinAnswer Express increased by more than 45percent compared to 2008.

On May 6, 2009, Rocky Mountain Power provided lighting training in combination with the Northwest regional trade ally network training in Idaho Falls, 49 individuals attended.

Cost Effectiveness

The program is cost effective on a TRC, UCT and PCT cost basis. Appendix 1 provides detailed inputs and assumptions used in the cost effectiveness analysis of this program.

Program Evaluation

Please see the discussion under the Program Evaluation heading in the 2009 Performance and Activities section of this report for evaluation activities related to this program.

Plans for Next Year

The Company will file changes for selected components of the lighting, motors, HVAC refrigeration offers to reflect the effects of changes in codes and standards.

Agricultural Energy Services (Schedule 155)

Agricultural Energy Services, marketed as Irrigation Energy Savers (Schedule 155), was available in 2009 to Idaho irrigation customers taking retail service on Schedule 10 through a Company contract with third-party program delivery vendor. The program design is intended to be the energy efficiency complement to the Irrigation Load Control programs offered under Schedules 72 & 72A. The 2009 program included the following customer service and measure components:

- Equipment Exchange – Provides new standard brass sprinkler nozzles to replace worn ones on hand lines, wheel lines and solid set sprinklers systems. Gasket and drain equipment also qualifies.
- Pivot and Linear Equipment Upgrades – Incentives are provided for certain pivot and linear system measures including sprinkler packages and regulators. The list of prescriptive incentives is not designed to be exhaustive and other pivot measures are eligible for incentives if energy savings can be calculated and the customer incurs costs to make the changes.
- System Consultation – This service provides a simple site specific audit of a customer's irrigation system to promote irrigation management and identify energy savings opportunities. This consultation provides information prior to a full pump test.
- Pump Testing – The pump test includes directly measuring pump lift, flow, electrical demands and system pressures and is performed after the pump has been screened and the owner's financial investment criteria understood.
- System Analysis – The program provides energy engineering to help growers quantify the costs and savings of their system efficiency upgrades. Often these upgrade decisions are made in conjunction with operational production change considerations impacting a growers equipment needs. Incentives are based on a standard formula tied to costs and first year energy savings.

The summary program results for 2009 are provided in the table below.

Table 14

2009 Agricultural Energy Services Program Performance					
kWh/Yr Savings 2009 (Gross - At Gen)	4,409,442				
Expenditures	$ 807,238				
Incentives Paid	$ 390,597				
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	0.947	0.861	1.696	0.740	1.684
Levelized Cost ($/kWh)	0.0979	0.0979	0.0497		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000098636				

Details of 2009 savings by type of measure are provided on the following table.

Table 15

Irrigation Energy Savers kWh/Yr Savings by Measure Type (at Site)

Equipment Exchange & Pivot/Linear Upgrade	2,564,171	64%
System Design	1,430,178	36%
	3,994,349	

Major Trends and Activities

On January 1, 2009, program delivery was transferred from the Franklin Soil and Water Conservation District to Nexant who was selected via a competitive procurement process in 2008.

The 2009 savings and expenses were 215 percent and 300 percent respectively of the 2008 program savings and expenditures.

During the 2009 calendar year 121 site visits were completed to obtain system information to be used in either a system consultation evaluation or an energy analysis evaluation as a part of the Agricultural Energy Services Program. During the same year, 49 post installation inspections were completed to verify project installation and energy savings.

The following outreach and event activities were completed for the program in 2009:

- Program presentation at the Idaho Irrigation Equipment Association's annual meeting and expo in Idaho Falls on January 7, 2009.
- Set up and operated a booth at the 2009 Agricultural Expo in Pocatello from January 20th to 22nd, 2009 to meet with customers and provide information about the program.
- Set up and operated a booth at the Rain For Rent customer appreciation day in Idaho Falls on February 26th, 2009 to provide program information to customers.
- Gave on site presentations to 11 irrigation dealers in Rexburg, Idaho Falls, Ucon, Blackfoot, American Falls, Aberdeen, Preston, and Arco with an overview of program components and the new program manual during the months of April and May, 2009.

Cost Effectiveness

The 2009 Agricultural Energy Services program is cost effective from a UCT standpoint however it did not pass the TRC.

Two primary factors contributed to this result; 1) the contribution of onetime and non-recurring transition costs associated with changing program administrators; and 2) customer specific costs associated with equipment investments that delivered operational efficiencies in addition to energy efficiency benefits. The simple pre-incentive pay-back for all 2009 projects completed through the program was 5.7 years however seven of these projects had simple paybacks of between 15 and 20 years. The additional customer costs from these seven projects had a negative impact on the TRC results from a strictly electric energy savings perspective. The projects accounted for about 50 percent of the total customer costs reported by the program and were offset by utility incentives equal to about 12 percent heavily influencing overall program results. The Company acknowledges that most customers don't make uneconomic investments therefore there must be additional benefits beyond just electrical savings that compelled these customers to proceed with the projects. While the Company could have expended additional resources to quantify these non-energy benefits and improve the test results the Company elected to provide the results using only electric benefits and reserve a further accounting of the additional customer benefits for the program evaluation. For any long payback projects such as those described above that are eligible for incentives, the current program administrator will take extra steps to align energy and non-energy benefits with project costs prior to project close-out and reporting project costs. As a result, this impact on the program's TRC results is not expected to recur and the program is forecasted to be cost effective under both the TRC and UCT perspectives in 2010.

Several factors contribute to higher overall forecasted program expenses when compared with prior program delivery, not the least of which is moving beyond nozzle exchanges to more complex and expensive project measures. In response to grower needs the program administrator is providing improved service to irrigation dealers and growers including faster turnaround and increased technical rigor for site work intended to improve customer service and program performance.

Program Evaluation

In October, 2009, the Company initiated process and impact evaluations for the Agricultural Energy Services program for program years 2006 – 2008. To acquire the most accurate impact evaluation information, site visits will need to be performed when the irrigation systems are fully operational. As a result, information from this evaluation will be available in the third quarter of 2010. Findings from these evaluations will be key inputs to on-going program design and modification as well as inputs to future cost effectiveness determinations.

No process, impact or market impact evaluations were completed on the program during 2009.

Plans for Next Year

The program administrator has analyzed further changes to this program to increase prescriptive incentives and better align with other programs, including those of Idaho Power and the Bonneville Power Administration. The Company may propose modifications to the program to include additional promising measures.

Market Transformation - Northwest Energy Efficiency Alliance

The Northwest Energy Efficiency Alliance (NEEA) is a non-profit organization working to encourage the development and adoption of energy efficient products and services through a regional market transformation model. NEEA is supported by the region's electric utilities, public benefits administrators, state governments, public interest groups and efficiency industry representatives.

The Company provides funding for NEEA through a multi-year commitment helping support their activities in Idaho and Washington. NEEA activities for all sectors are fully described on their web site at www.nwalliance.org. Rocky Mountain Power expenditures allocated to Idaho for NEEA in 2009 totaled $287,190. The associated Idaho savings attributed from the Company's Idaho customers as reported by NEEA for the same period were 5,914,896 kWh at site.

For the results displayed in the graphical comparisons section, energy savings from NEEA activities were allocated to customer sectors based on information provided by NEEA. This allocation is based on region-wide NEEA results by sector. Rocky Mountain Power's NEEA funding allocated to customer sectors was done in the same ratios as NEEA's reported energy savings.

In addition to funding, the Company participates in the sector advisory groups, provides input on NEEA activity effectiveness, and works to coordinate the delivery of NEEA products and serves with those of the Company's programs. The Company continues to work with NEEA regarding ways to increase their activities and results across all sectors and in smaller and more rural markets such as Rocky Mountain Power's Idaho service territory.

Further information about NEEA can be found at the following website http://www.nwalliance.org/

Major Trends and Activities

In September 2009, the Northwest Power and Conservation Council released a draft of the Sixth Power Plan which identified approximately twice the cost effective conservation potential as that included in the Fifth Power plan. The Sixth Power Plan identifies NEEA as a key implementer in achieving the higher levels of conservation and includes NEEA funding by the regional utilities as a specific action item (CONS-3). In the residential market, NEEA's work in transforming the split system heat pump market has the potential to help reduce space heating energy use by approximately 200 average megawatts.

Cost-Effectiveness

NEEA has traditionally used a “net market effects” approach to identify savings attributable to market transformation. This analytical approach estimates utility program activity and the “baseline” level of market activity. The net difference between these activities and the total regional activity is attributed to NEEA. Cost effectiveness for the net market effect savings are assessed from both a total resource and program administrator perspective. While the company has access to the reported results we do not directly control the work which is performed at a regional level. For these reasons, the company has traditionally included the NEEA costs and energy savings in reported results, but does not include these inputs in our portfolio level cost effectiveness results.

Program Evaluation

NEEA’s approach to evaluations is appropriately more focused on regional changes in markets instead of site specific installed savings assessments typically identified in local conservation impact and process evaluations. For these reasons, the company utilizes NEEA’s evaluation of their initiatives and does not attempt to replicates them for a specific territory.

Plans for Next Year

NEEA’s 2010-2014 funding cycle request has been provided to the Company. The Company is reviewing the request, the plans to increase activity in smaller markets and its rate impact on Idaho customers.

Summary of 2009 Results:

Table 16

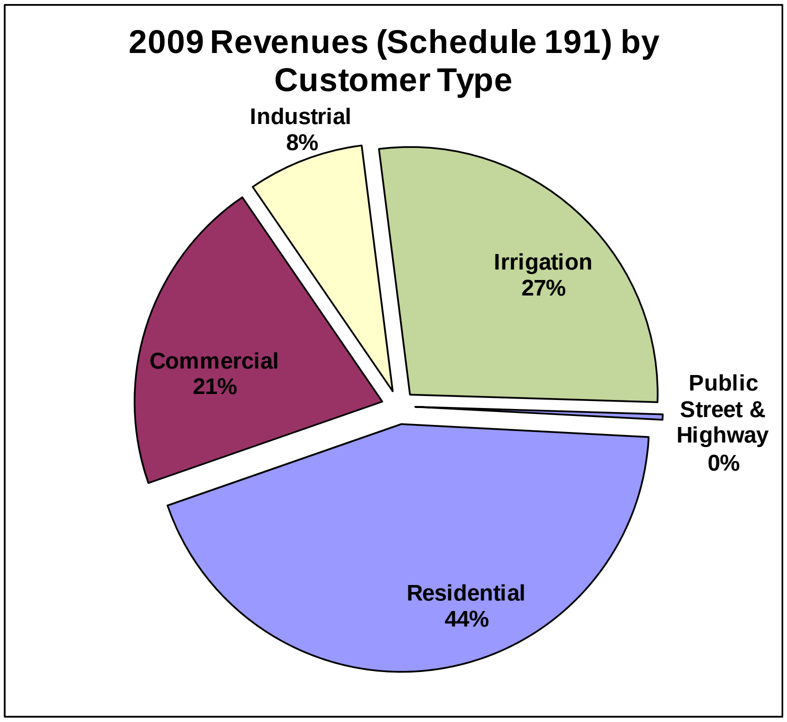
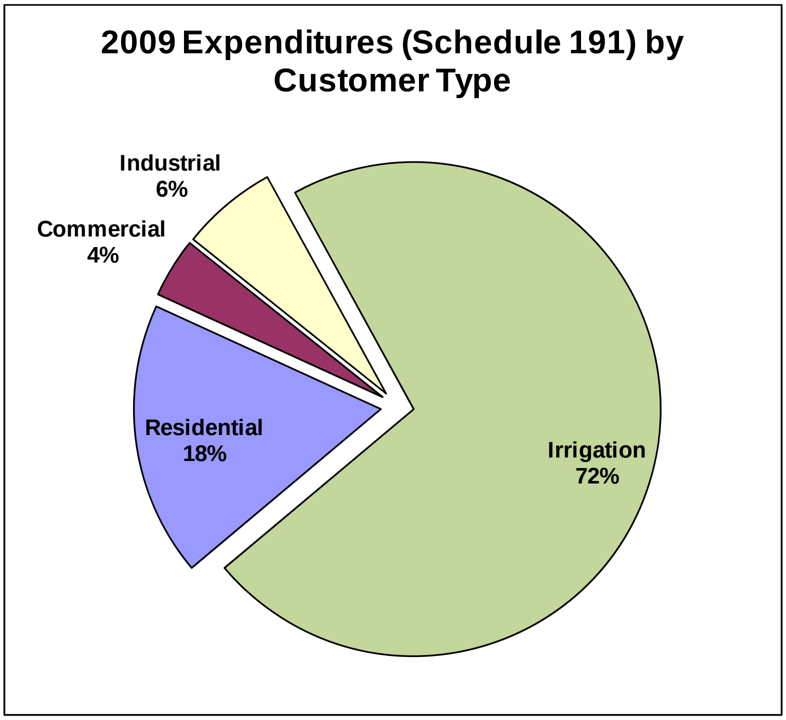
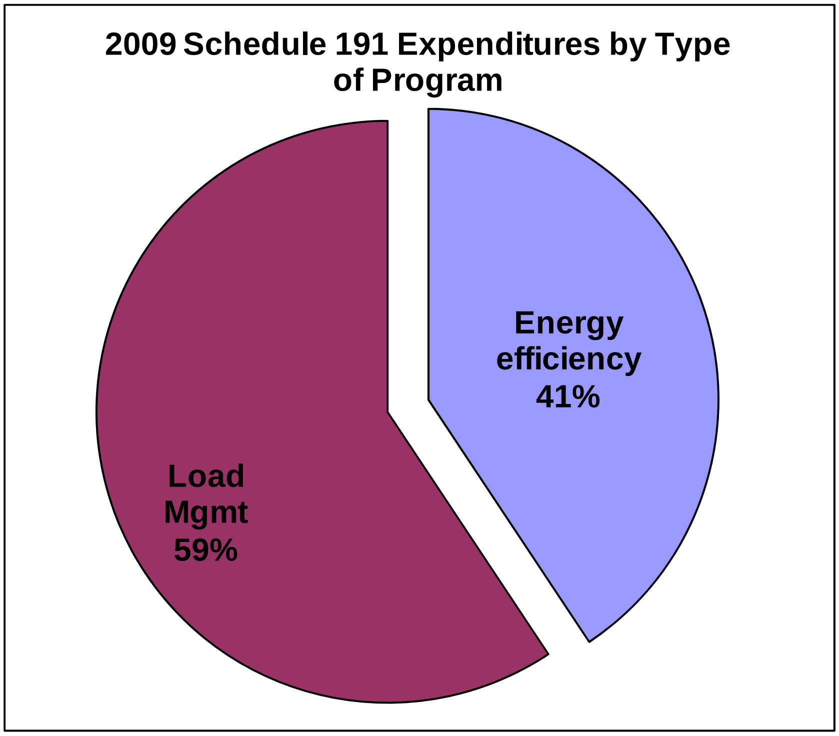


Table 17



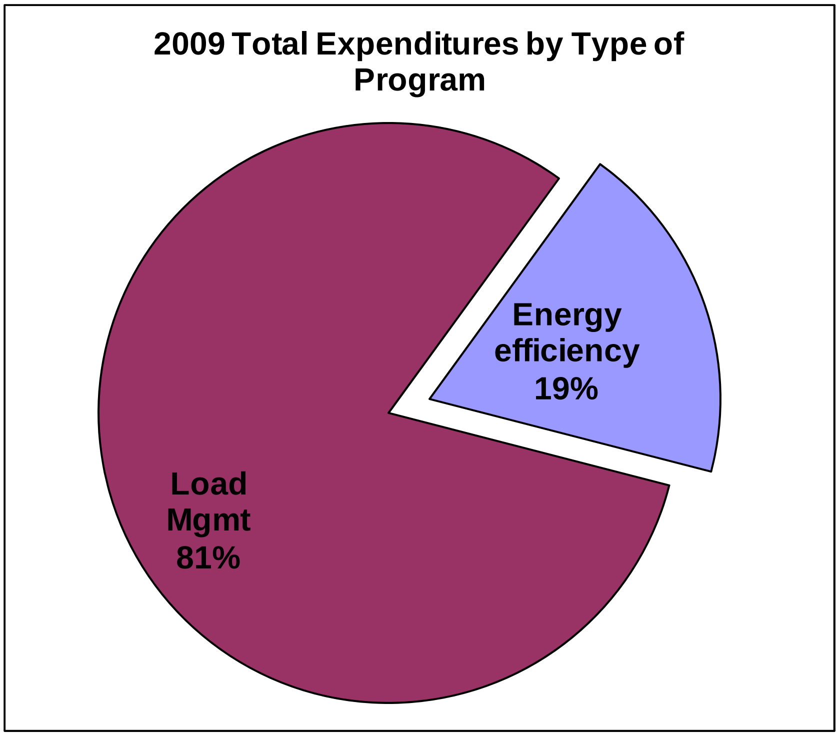
(Note – Table 17 does not include Irrigation Load Control Service Credits

Table 18



(Note – Table 18 does not include Irrigation Load Control Service Credits

Table 19



(Note – Table 19 includes Schedule 191 expenditures and Irrigation Load Control Service Credits

Table 20

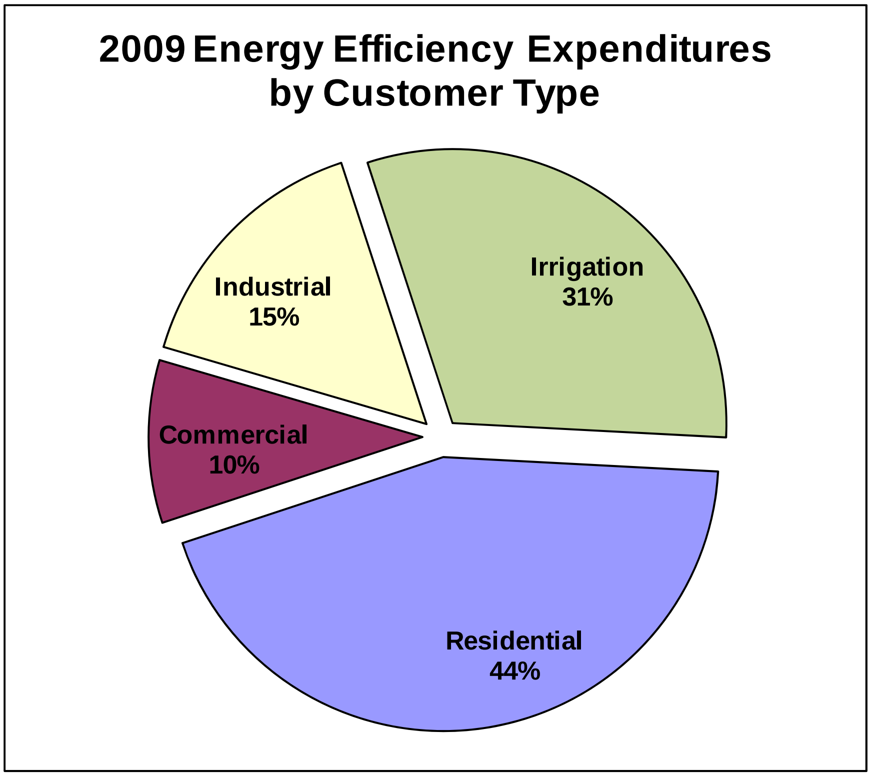
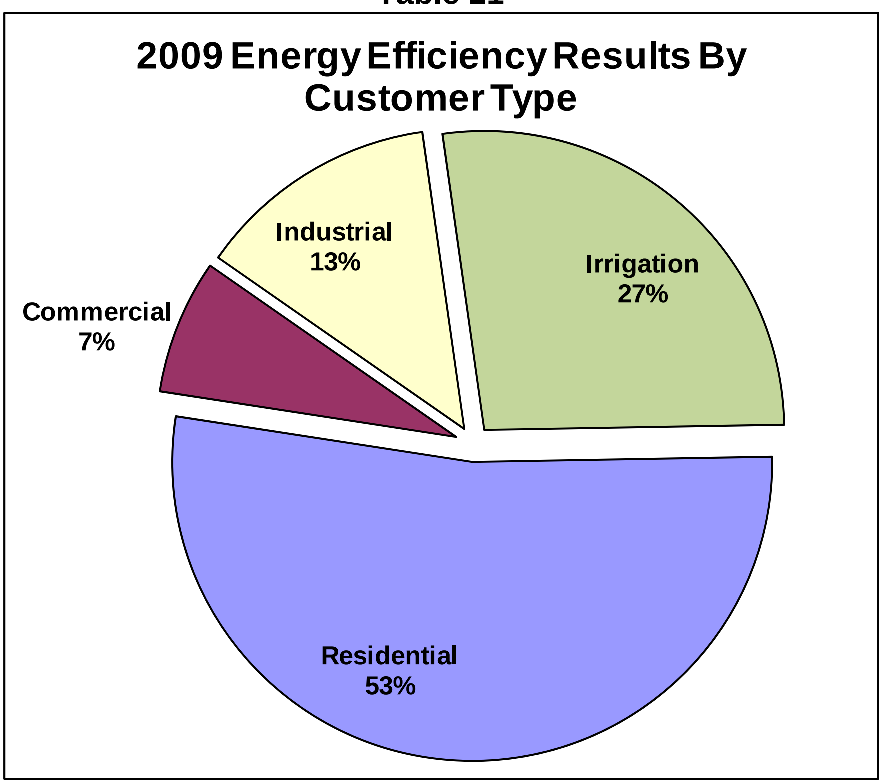


Table 21



Balancing Account Summary

Demand Side Management activities are funded by revenue collected through Schedule 191, Customer Efficiency Services Rate Adjustment charge on customer bills. Expenses for demand side management expenditures are charged as incurred and booked to the balancing account. The demand side management balancing account activity for 2009 is outlined in the table below.

Table 22
Balancing Account Activity 2009 (Schedule 191)

	Monthly Program Cost - Fixed Assets	Rate Recovery	Carrying Charge	Accumulated Balance
				Balance as of 12/31/08
				$ 770,450.84
January	$ 593,500.04	$ (368,584.62)	$ 1,472.00	$ 996,838.26
February	$ 247,672.00	$ (330,653.18)	$ 1,592.00	$ 915,449.08
March	$ 293,972.99	$ (295,538.43)	$ 1,524.00	$ 915,407.64
April	$ 860,455.46	$ (270,113.24)	$ 15,755.00	$ 1,521,504.86
May	$ 812,465.90	$ (339,685.26)	$ 2,930.00	$ 1,997,215.50
June	$ 484,589.23	$ (490,841.32)	$ 3,323.00	$ 1,994,286.41
July	$ 578,847.73	$ (608,542.13)	$ 3,299.00	$ 1,967,891.01
August	$ 373,212.18	$ (700,049.91)	$ 3,007.00	$ 1,644,060.28
September	$ 720,006.31	$ (522,941.92)	$ 2,904.00	$ 1,844,028.67
October	$ 626,325.15	$ (391,560.70)	$ 3,269.00	$ 2,082,062.12
November	$ 341,917.49	$ (327,278.14)	$ 3,482.00	$ 2,100,183.47
December	$ 499,720.73	$ (364,696.93)	$ 3,613.00	**$ 2,238,820.27**
2009 totals	**$ 6,432,685.21**	**$ (5,010,485.78)**	**$ 46,170.00**	

Column Explanations:

Monthly Program Costs – Fixed Assets: Monthly expenditures for all DSM program activities
Rate Recovery: Revenue collected through Schedule 191, DSM cost adjustment rider.
Carrying Charge: Monthly “interest” charge based on “Accumulated Balance” of the account. The current “interest rate” for the Accumulated Balance is 2 percent per year.
Accumulated Balance: Current balance of the account. A running total of account activities. If more is collected in “Revenue” than is spent “Monthly Program Costs” for a given month, then the Accumulated Balance” will be decreased by the net amount.

At the beginning of 2009, the unfunded balance was approximately $770, 000 and increased by approximately $1,468,000 during 2009. The unfunded balance at the end of 2009 is $2.239 million.

Cost Effectiveness:

Introduction

The cost effectiveness of individual programs operated by the Company for 2009 are calculated using actual expenditures and reported savings. Cost-effectiveness is provided at the individual program, load management portfolio, residential energy efficiency portfolio, non-residential energy efficiency portfolio, combined energy efficiency portfolio, and overall demand side management program portfolio levels. Deemed savings estimates where applicable were the same as those used in the planning estimates, unless more recent estimates were available from evaluations.

Energy savings shown in this report are gross savings and the impact of line losses is indicated with an at "site" or at "generation" designation. Line losses are based on the Company's 2001 line loss study. Net-to-gross assumptions are consistent with planning estimates. The energy savings attributed to each program are shaped according to specific end-use savings (the hourly calculation of when energy is used for the various end-use measures from which the savings are derived). Program costs and the value of the energy savings are then compared on a present value basis with the Company's 2008 Integrated Resource Plan (IRP) calculated decrement values for demand-side resource savings and avoided capacity investments. The energy efficiency resource decrement values are fully shaped to represent the 8,760 hourly values that exist within a calendar year. By matching the hourly savings with the hourly avoided costs, both energy and capacity impacts of energy efficiency savings are recognized.

The cost/benefit analysis of the load management programs are based on the avoided value of peak or capacity investments. For purposes of calculating program cost-effectiveness no energy savings are included for the load management programs, only a shift of when the energy is used away from the peak load hours. The five California Standard Practice Manual cost effectiveness tests were utilized in the cost benefit analysis for both energy efficiency and load management programs. Tables 22 through 33 below provide the cost benefit test results for the 2009 programs. Further details are available in Appendix 1.

Key Assumptions for Cost Effectiveness Calculations:

Cost Effectiveness calculations for Programs and Measures (or measure groups) within each program will be detailed on the following tables.

Global Assumptions used in all cost effectiveness calculations include:

Table 23

Key Assumptions for All Cost Effectiveness Studies:

Assumption	Value	Source
Discount Rate	7.40%	2008 IRP
Line Losses (Idaho Specific)		
Residential	11.389%	2001 MAC Line Loss Study
Commercial	10.698%	2001 MAC Line Loss Study
Industrial	10.392%	2001 MAC Line Loss Study

Key elements that go into the cost effectiveness calculation for each program include:

KW/kWh Savings Gross
Administrative Expenses
Incentives Paid
Total Utility costs – including administration and evaluation

Gross Customer Costs
Net To Gross Ratio
Measure Life

IRP Decrement Value

Please reference Appendix 1, 2009 Cost Effectiveness and Evaluation Details for additional information on the key assumptions and inputs for cost effectiveness calculations for each program.

Portfolio Cost Effectiveness

The overall demand side management portfolio and component sectors were all cost effective on a Total Resource Cost and Utility Cost basis. As expected, only the Load Control component generated a Ratepayer Impact Test of greater than 1.0.

The following table provides the overall portfolio and sector results of all 5 cost effectiveness tests. (Please refer to the Cost Effectiveness Appendix 1 to this report for more information on the cost effectiveness tests and the assumptions and inputs).

Table 24

2009 Portfolio and Sector Cost Effectiveness Summary

	Cost Effectiveness Test				
	PTRC	TRC	UCT	RIM	PCT
2009 Program Portfolio Including Irrigation Load Control	3.731	3.392	1.831	1.470	9.734
2009 Irrigation Load Control	5.808	5.280	1.813	1.813	n/a
2009 Energy Efficiency Program Portfolio	1.367	1.242	1.927	0.768	3.603
2009 Residential Program Portfolio	1.530	1.391	1.641	0.694	10.737
2009 Non-residential Program Portfolio	1.299	1.181	2.108	0.810	2.568

Cost Effectiveness Results for each Sector and Program are provided below.

Table 25

2009 Program Portfolio Including Irrigation Load Control

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$7,167,160	$26,743,767	$19,576,607	3.731
Total Resource Cost Test (TRC) No Adder		$7,167,160	$24,312,516	$17,145,355	3.392
Utility Cost Test (UCT)		$13,275,355	$24,312,516	$11,037,160	1.831
Rate Impact Test (RIM)		$16,537,350	$24,312,516	$7,775,166	1.47
Participant Cost Test (PCT)		$1,190,336	$11,587,079	$10,396,743	9.734
Lifecycle Revenue Impacts ($/kWh)					

Table 26

2009 Irrigation Load Control

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$3,816,417	$22,164,322	$18,347,905	5.808
Total Resource Cost Test (TRC) No Adder		$3,816,417	$20,149,384	$16,332,967	5.280
Utility Cost Test (UCT)		$11,114,948	$20,149,384	$9,034,436	1.813
Rate Impact Test (RIM)		$11,114,948	$20,149,384	$9,034,436	1.813
Participant Cost Test (PCT)		$0	$7,298,531	$7,298,531	n/a
Lifecycle Revenue Impacts ($/kWh)					

Table 27

2009 Energy Efficiency Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0681	$3,350,743	$4,579,445	$1,228,702	1.367
Total Resource Cost Test (TRC) No Adder	0.0681	$3,350,743	$4,163,131	$812,389	1.242
Utility Cost Test (UCT)	0.0439	$2,160,407	$4,163,131	$2,002,724	1.927
Rate Impact Test (RIM)		$5,422,401	$4,163,131	($1,259,270)	0.768
Participant Cost Test (PCT)		$1,190,336	$4,288,548	$3,098,212	3.603
Lifecycle Revenue Impacts ($/kWh)				$0.000030233	

Table 28

2009 Residential Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0675	$988,283	$1,511,639	$523,356	1.53
Total Resource Cost Test (TRC) No Adder	0.0675	$988,283	$1,374,217	$385,935	1.391
Utility Cost Test (UCT)	0.0572	$837,532	$1,374,217	$536,685	1.641
Rate Impact Test (RIM)		$1,980,974	$1,374,217	($606,757)	0.694
Participant Cost Test (PCT)		$150,751	$1,618,585	$1,467,835	10.737
Lifecycle Revenue Impacts ($/kWh)				$0.000007928	

Table 29

2009 Home Energy Savings Program

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0616	$723,668	$1,052,066	$328,398	1.454
Total Resource Cost Test (TRC) No Adder	0.0616	$723,668	$956,424	$232,755	1.322
Utility Cost Test (UCT)	0.0470	$552,666	$956,424	$403,757	1.731
Rate Impact Test (RIM)		$1,325,391	$956,424	($368,968)	0.722
Participant Cost Test (PCT)		$171,002	$1,103,461	$932,459	6.453
Lifecycle Revenue Impacts ($/kWh)				$0.0000045779	

Table 30

2009 Refrigerator Recycling Program(See Ya Later Refrigerator)

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0317	$80,425	$180,651	$100,226	2.246
Total Resource Cost Test (TRC) No Adder	0.0317	$80,425	$164,228	$83,803	2.042
Utility Cost Test (UCT)	0.0397	$100,676	$164,228	$63,552	1.631
Rate Impact Test (RIM)		$290,904	$164,228	($126,676)	0.565
Participant Cost Test (PCT)		($20,251)	$237,626	$257,878	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000046624	

Table 31

2009 Low Income Weatherization

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0479	$184,190	$278,922	$94,732	1.514
Total Resource Cost Test (TRC) No Adder	0.0479	$184,190	$253,566	$69,376	1.377
Utility Cost Test (UCT)	0.0479	$184,190	$253,566	$69,376	1.377
Rate Impact Test (RIM)		$364,678	$253,566	($111,112)	0.695
Participant Cost Test (PCT)		$0	$277,498	$277,498	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000010946	

Table 32

2009 Non-residential Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0717	$2,362,460	$3,067,806	$705,345	1.299
Total Resource Cost Test (TRC) No Adder	0.0717	$2,362,460	$2,788,914	$426,454	1.181
Utility Cost Test (UCT)	0.0402	$1,322,875	$2,788,914	$1,466,039	2.108
Rate Impact Test (RIM)		$3,441,428	$2,788,914	($652,513)	0.81
Participant Cost Test (PCT)		$1,039,585	$2,669,962	$1,630,377	2.568
Lifecycle Revenue Impacts ($/kWh)				$0.000021233	

Table 33

2009 Energy FinAnswer Program

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0378	$502,893	$1,058,318	$555,425	2.104
Total Resource Cost Test (TRC) No Adder	0.0378	$502,893	$962,107	$459,214	1.913
Utility Cost Test (UCT)	0.0251	$333,730	$962,107	$628,377	2.883
Rate Impact Test (RIM)		$974,479	$962,107	($12,372)	0.987
Participant Cost Test (PCT)		$169,163	$847,899	$678,736	5.012
Lifecycle Revenue Impacts ($/kWh)				$0.0000002336	

Table 34

2009 FinAnswer Express Program

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0577	$379,621	$607,387	$227,766	1.600
Total Resource Cost Test (TRC) No Adder	0.0577	$379,621	$552,170	$172,549	1.455
Utility Cost Test (UCT)	0.0361	$237,527	$552,170	$314,643	2.325
Rate Impact Test (RIM)		$744,677	$552,170	($192,506)	0.741
Participant Cost Test (PCT)		$142,095	$595,611	$453,517	4.192
Lifecycle Revenue Impacts ($/kWh)				$0.0000042419	

Table 35

2009 Agricultural Energy Services (Irrigation Energy Savings) Program

All Measures				AC: IRP 16% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0979	$1,479,946	$1,402,101	($77,845)	0.947
Total Resource Cost Test (TRC) No Adder	0.0979	$1,479,946	$1,274,637	($205,309)	0.861
Utility Cost Test (UCT)	0.0497	$751,618	$1,274,637	$523,019	1.696
Rate Impact Test (RIM)		$1,722,272	$1,274,637	($447,635)	0.74
Participant Cost Test (PCT)		$728,328	$1,226,452	$498,124	1.684
Lifecycle Revenue Impacts ($/kWh)				$0.000009864	

Appendices:

Appendix 1 – Cost Effectiveness and Evaluation Details

Appendix 2 – *2009 Idaho Load Control Program Quantitative Analysis*

Appendix 1
2009 Cost Effectiveness and Evaluation Details

Cost Effectiveness and Program Evaluation:

The cost effectiveness of individual programs operated by the Company for 2009 are calculated using actual expenditures and reported savings. Cost-effectiveness is provided at the individual program, load management portfolio, residential energy efficiency portfolio, non-residential energy efficiency portfolio, combined energy efficiency portfolio, and overall demand side management program portfolio levels. Deemed savings estimates where applicable were the same as those used in the planning estimates, unless more recent estimates were available from evaluations.

Energy savings shown in this report are gross savings and the impact of line losses is indicated through an at “site” or at “generation” designation. Line losses are based on the Company’s 2001 line loss study. Net-to-gross assumptions are consistent with planning estimates. The energy savings attributed to each program are shaped according to specific end-use savings (the hourly calculation of when energy is used for the various end-use measures from which the savings are derived). Program costs and the value of the energy savings are then compared on a present value basis with the Company’s 2008 Integrated Resource Plan (IRP) calculated decrement values for demand-side resource savings and avoided capacity investments. The energy efficiency resource decrement values are fully shaped to represent the 8,760 hourly values that exist within a calendar year. By matching the hourly savings with the hourly avoided costs, both energy and capacity impacts of energy efficiency savings are recognized. The cost/benefit analysis of the load management programs are based on the avoided value of peak or capacity investments. For purposes of calculating program cost-effectiveness no energy savings are included for the load management programs, only a shift of when the energy is used away from the peak load hours. The five California Standard Practice Manual cost effectiveness tests were utilized in the cost benefit analysis for both energy efficiency and load management programs.

The Company updates the cost effectiveness results annually based on actual annual results. Key inputs like net to gross ratios, measure life and deemed savings values will be updated as formal evaluations are completed and during the course of normal maintenance of programs. Company program managers with input from third-party delivery vendors make determinations about changes to key cost effectiveness inputs. Any changes will be noted in future DSM Annual Reports.

In the future, the company intends to complete process and impact evaluations on a two to three year cycle for each program in the demand side management portfolio. Exact timing and frequency of formal evaluations will vary depending on maturity of program, experience with the program in other jurisdictions and various other factors including potential cost of evaluation.

No market effects evaluations were completed on programs in the Company demand side management portfolio during 2009. The Company does plan to update its *2007 Assessment of Long-Term System Wide Potential for Demand Side and Supplemental Resources* during 2010.

Aside from the savings and expenditures associated with the Company's participation in the Northwest Energy Efficiency Alliance (NEEA), the Company does not claim any savings associated with behavioral changes or market effects in its Idaho jurisdiction. Company program managers will review and utilize results and data from NEEA studies in consideration of program enhancements or modifications.

Further information about NEEA, past and on-going studies and results can be found at the following website http://www.nwalliance.org/.

Key Assumptions for Cost Effectiveness Calculations:

Cost Effectiveness calculations for Programs and Measures (or measure groups) within each program will be detailed on the following tables.

Global Assumptions used in all cost effectiveness calculations include:

Key Assumptions for All Cost Effectiveness Studies:

Assumption	Value	Source
Discount Rate	7.40%	2008 IRP
Line Losses (Idaho Specific)		
Residential	11.389%	2001 MAC Line Loss Study
Commercial	10.698%	2001 MAC Line Loss Study
Industrial	10.392%	2001 MAC Line Loss Study

Key elements that go into the cost effectiveness calculation for each program include:

KW/kWh Savings Gross
Administrative Expenses
Incentives Paid
Total Utility costs – including administration and evaluation

Gross Customer Costs
Net To Gross Ratio
Measure Life

IRP Decrement Value

The following Tables provide details for the key assumptions and inputs for cost effectiveness calculations for each program.

Portfolio and Sector Level Cost Effectiveness

The overall DSM portfolio and component sectors were all cost effective on a Total Resource Cost and Utility Cost basis. As expected, only the Load Control component generated a Ratepayer Impact Test of greater than 1.0.

The following table provides the overall portfolio and sector results of all 5 cost effectiveness tests. (Please refer to the Cost Effectiveness Appendix 1 to this report for more information on the cost effectiveness tests and the assumptions and inputs).

Table 1

2009 Portfolio and Sector Cost Effectiveness Summary

	Cost Effectiveness Test				
	PTRC	**TRC**	**UCT**	**RIM**	**PCT**
2009 Program Portfolio Including Irrigation Load Control	3.731	3.392	1.831	1.470	9.734
2009 Irrigation Load Control	5.808	5.280	1.813	1.813	n/a
2009 Energy Efficiency Program Portfolio	1.367	1.242	1.927	0.768	3.603
2009 Residential Program Portfolio	1.530	1.391	1.641	0.694	10.737
2009 Non-residential Program Portfolio	1.299	1.181	2.108	0.810	2.568

Portfolio and Segment Level Cost Effectiveness Summaries:

The cost effectiveness results for the portfolio level and segment level are aggregations of the costs and benefits from the component programs. The inputs and assumptions that support these results are contained in the program level cost effectiveness results.

2009 Program Portfolio Including Irrigation Load Control

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$7,167,160	$26,743,767	$19,576,607	3.731
Total Resource Cost Test (TRC) No Adder		$7,167,160	$24,312,516	$17,145,355	3.392
Utility Cost Test (UCT)		$13,275,355	$24,312,516	$11,037,160	1.831
Rate Impact Test (RIM)		$16,537,350	$24,312,516	$7,775,166	1.47
Participant Cost Test (PCT)		$1,190,336	$11,587,079	$10,396,743	9.734
Lifecycle Revenue Impacts ($/kWh)					

2009 Irrigation Load Control

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$3,816,417	$22,164,322	$18,347,905	5.808
Total Resource Cost Test (TRC) No Adder		$3,816,417	$20,149,384	$16,332,967	5.280
Utility Cost Test (UCT)		$11,114,948	$20,149,384	$9,034,436	1.813
Rate Impact Test (RIM)		$11,114,948	$20,149,384	$9,034,436	1.813
Participant Cost Test (PCT)		$0	$7,298,531	$7,298,531	n/a
Lifecycle Revenue Impacts ($/kWh)					

2009 Energy Efficiency Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0681	$3,350,743	$4,579,445	$1,228,702	1.367
Total Resource Cost Test (TRC) No Adder	0.0681	$3,350,743	$4,163,131	$812,389	1.242
Utility Cost Test (UCT)	0.0439	$2,160,407	$4,163,131	$2,002,724	1.927
Rate Impact Test (RIM)		$5,422,401	$4,163,131	($1,259,270)	0.768
Participant Cost Test (PCT)		$1,190,336	$4,288,548	$3,098,212	3.603
Lifecycle Revenue Impacts ($/kWh)				$0.000030233	

2009 Residential Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0675	$988,283	$1,511,639	$523,356	1.53
Total Resource Cost Test (TRC) No Adder	0.0675	$988,283	$1,374,217	$385,935	1.391
Utility Cost Test (UCT)	0.0572	$837,532	$1,374,217	$536,685	1.641
Rate Impact Test (RIM)		$1,980,974	$1,374,217	($606,757)	0.694
Participant Cost Test (PCT)		$150,751	$1,618,585	$1,467,835	10.737
Lifecycle Revenue Impacts ($/kWh)				$0.000007928	

2009 Non-residential Program Portfolio

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder	0.0717	$2,362,460	$3,067,806	$705,345	1.299
Total Resource Cost Test (TRC) No Adder	0.0717	$2,362,460	$2,788,914	$426,454	1.181
Utility Cost Test (UCT)	0.0402	$1,322,875	$2,788,914	$1,466,039	2.108
Rate Impact Test (RIM)		$3,441,428	$2,788,914	($652,513)	0.81
Participant Cost Test (PCT)		$1,039,585	$2,669,962	$1,630,377	2.568
Lifecycle Revenue Impacts ($/kWh)				$0.000021233	

Program Level Cost Effectiveness

Home Energy Savings Program – Schedule 118

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Home Energy Savings		
Gross kWh/Year Savings (at Site)	1,349,280	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 238,650	Annual costs 2009
Incentives	$ 354,913	Annual costs 2009
Total Utility Costs	$ 593,563	Annual costs 2009
Total Participant Costs	$ 673,212	Deemed costs per unit * unit participation. Deemed costs per unit is from a variety of sources, including Regional Technical Forum, Energy Star and analysis of invoices submitted with incentive applications Developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.8	Planning estimate from original program filing (2006) and used for prior annual reports cost effectiveness assessments.
Measure Life		At program level, it is a weighted average of the measure group inputs.

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0616	$723,668	$1,052,066	$328,398	1.454
Total Resource Cost Test (TRC) No Adder	0.0616	$723,668	$956,424	$232,755	1.322
Utility Cost Test (UCT)	0.0470	$552,666	$956,424	$403,757	1.731
Rate Impact Test (RIM)		$1,325,391	$956,424	($368,968)	0.722
Participant Cost Test (PCT)		$171,002	$1,103,461	$932,459	6.453
Lifecycle Revenue Impacts ($/kWh)				$0.0000045779	

Measure Group Inputs and Assumptions:

Lighting (Includes CFLs, Fixtures and Ceiling Fans)	**Value**	**Source and Notes**
Gross kWh/Year Savings (at Site)	606,103	Annual results 2009 (Gross at Site) based on measure level savings from Energy Star savings calculator 2008 and RTF PTR Software 2007
Program Management and Administration Costs	$ 107,203	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 30,842	Annual costs 2009
Total Utility Costs	$ 138,045	Annual costs 2009
Total Participant Costs	$ 122,996	Deemed based on RTF estimates developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.8	Planning estimate from original program filing (2006) and used for prior annual reports cost effectiveness assessments.
Measure Life (Years)	9	RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
2008 IRP Decrement Load Shape		East Side Residential Lighting

Appliances (Clothes Washers, Dishwasher, Water Heater, Refrigerator)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	295,042	Annual results 2009 (Gross at Site) based on measure level savings from RTF PTR Software 2007
Program Management and Administration Costs	$ 52,185	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 114,550	Annual costs 2009
Total Utility Costs	$ 166,735	Annual costs 2009
Total Participant Costs	$ 273,698	Deemed based on RTF and Energy Star estimates developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.8	Planning estimate from original program filing (2006) and used for prior annual reports cost effectiveness assessments.
Measure Life (Years)	15	Average life for group based on measure level inputs from RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
2008 IRP Decrement Load Shape		East Side Residential Whole House

Shell Measures (Insulation and Windows)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	431,396	Annual results 2009 (Gross at Site) based on measure level inputs from RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
Program Management and Administration Costs	$ 76,302	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 190,546	Annual costs 2009
Total Utility Costs	$ 266,848	Annual costs 2009
Total Participant Costs	$ 239,992	Windows deemed based on RTF. Insulation is based on application analysis.
Net To Gross Ratio	0.8	Planning estimate from original program filing (2006) and used for prior annual reports cost effectiveness assessments.
Measure Life (Years)	45	RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
2008 IRP Decrement Load Shape		East Side Residential Whole House

HVAC (AC and Heat Pump Equipment, Tune ups, Proper Installations, Duct Sealing)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	16,739	Annual results 2009 (Gross at Site) based on measure level inputs from Quantec Evaluation 2006, Research from Energy Trust of Oregon 2007, and RTF PTR Software Version 1.0 + Research by Gary Smith 2006.
Program Management and Administration Costs	$ 2,961	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 18,975	Annual costs 2009
Total Utility Costs	$ 21,936	Annual costs 2009
Total Participant Costs	$ 36,526	Incremental costs for HVAC measures based on Utah cool cash program. Tune-ups & heat pumps - RTF. Duct sealing - PTCS/RTF. Developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.8	Planning estimate from original program filing (2006) and used for prior annual reports cost effectiveness assessments.
Measure Life (Years)	15	Average life. Combination of RTF and Cool Cash
2008 IRP Decrement Load Shape		East Side Residential Cooling

Home Energy Savings Measure Level Cost effectiveness Inputs - 2009 Idaho

Type	Measures	2009 Gross kWh Savings	Net To Gross Ratio	2009 NET kWh Savings	Measure Life (Years)	2009 Savings Source	Measure Life Used for Measure Groups for Program CE	Source Details
Appliance	Clothes Washer-Tier One	226	0.80	181	14	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Appliance	Clothes Washer-Tier Two	250	0.80	200	18	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Appliance	Dishwasher	33	0.80	26	9	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Appliance	Electric Water Heater	91	0.80	73	10	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Appliance	Refrigerator	98	0.80	78	22	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
HVAC	Evaporative Cooler	325	0.80	260	15	Quantec[4]	15	4-Quantac-2006 Evaportative Cooling and Central Air Conditioning Incentive Program: Evaluation
HVAC	CAC/HP Tune up	42	0.80	34	5	RTF[3]	15	3-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
HVAC	Central A/C Equipment	96	0.80	77	18	Quantec[4]	15	4-Quantac-2006 Evaportative Cooling and Central Air Conditioning Incentive Program: Evaluation
HVAC	Duct Sealing - Electric	2,150	0.80	1,720	20	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
HVAC	Duct Sealing - Gas	40	0.80	32	20	RTF[2]	15	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
HVAC	Heat Pump Conversion	3,147	0.80	2,518	18	Energy Trust[5]	15	5-Research-Energy Trust of Oregon-2007
HVAC	Heat Pump Upgrade	811	0.80	649	18	Energy Trust[5]	15	5-Research-Energy Trust of Oregon-2007
HVAC	Proper CAC Install	23	0.80	18	18	Quantec[4]	15	4-Quantac-2006 Evaportative Cooling and Central Air Conditioning Incentive Program: Evaluation
HVAC	Proper CAC Sizing	67	0.80	54	18	Quantec[4]	15	4-Quantac-2006 Evaportative Cooling and Central Air Conditioning Incentive Program: Evaluation
Lighting	Ceiling Fans	107	0.80	86	15	Energy Star[1]	9	1-www.energystar.gov savings calculator-2008
Lighting	Fixtures	92	0.80	74	15	RTF[2]	9	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Lighting	CFLs	25	0.80	20	9	RTF[2]	9	2-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)
Shell	Insulation: Attic	0.63	0.80	0.50	45	RTF[3]	45	3-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
Shell	Insulation: Floor	0.60	0.80	0.48	45	RTF[3]	45	3-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
Shell	Insulation: Wall	0.95	0.80	0.76	45	RTF[3]	45	3-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
Shell	Windows	0.74	0.80	0.59	45	RTF[3]	45	3-RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company has initiated a process and impact evaluation for the program for program years 2006 to 2008. Results of those evaluations are expected to be complete in the second quarter of 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Rocky Mountain Power conducted a competitive bidding process and selected The Cadmus Group to perform the evaluations. No evaluation expenses were incurred for this effort in 2009. The Company considers evaluation costs resulting from a competitive bidding process to be confidential. The Company will provide confidential evaluation cost information to the Commission and Commission Staff under signed protective agreements.

In the future, the Company intends to complete process and impact evaluations on a two to three years cycle for each program in the demand side management portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Refrigerator Recycling (See ya later, refrigerator) – Schedule 117

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - See ya later, refrigerator			
Gross kWh/Year Savings (at Site)		957,819	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$	86,376	Annual costs 2009
Incentives	$	21,750	Annual costs 2009
Total Utility Costs	$	108,126	Annual costs 2009
Total Participant Costs		NA	There are no participant costs for this program.
Net To Gross Ratio			Utilize measure specific savings and Net To Gross
Measure Life (Years)		8	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0317	$80,425	$180,651	$100,226	2.246
Total Resource Cost Test (TRC) No Adder	0.0317	$80,425	$164,228	$83,803	2.042
Utility Cost Test (UCT)	0.0397	$100,676	$164,228	$63,552	1.631
Rate Impact Test (RIM)		$290,904	$164,228	($126,676)	0.565
Participant Cost Test (PCT)		($20,251)	$237,626	$257,878	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000046624	

Measure Group Inputs and Assumptions:

Refrigerators	**Value**	**Source and Notes**
Number of Units	566	Annual results 2009
Gross kWh/Unit	1,149	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	650,334	Annual results 2009 (Gross at Site)
Net To Gross Ratio	0.33	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Measure Life (Years)	8	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
2008 IRP Decrement Load Shape		East Side Residential Whole House

Freezers	Value	Source and Notes
Number of Units	159	Annual results 2009
Gross kWh/Unit	1,590	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	252,810	Annual results 2009 (Gross at Site)
Net To Gross Ratio	0.58	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Measure Life (Years)	8	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
2008 IRP Decrement Load Shape		East Side Residential Whole House

Savings Kits	Value	Source and Notes
Number of Units	675	Annual results 2009
Gross kWh/Unit	81	Evaluation of Utah Refrigerator Recycling Program - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	54,675	Annual results 2009 (Gross at Site)
Net To Gross Ratio	0.73	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Measure Life (Years)	8	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007. Evaluation indicated 5 year measure life, but with kit savings accounting for only 6% of the savings and being generated primarily by CFLs (9 yr life), the program was assessed using an overall 8 year measure life.
2008 IRP Decrement Load Shape		East Side Residential Whole House

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company has initiated a process and impact evaluation for the program for program years 2006 to 2008. Results of those evaluations are expected to be complete in the second quarter of 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Rocky Mountain Power conducted a competitive bidding process and selected The Cadmus Group to perform the evaluations. No evaluation expenses were incurred for this effort in 2009. The Company considers evaluation costs resulting from a competitive bidding process to be confidential. The Company will provide confidential evaluation cost information to the Commission and Commission Staff under signed protective agreements.

In the future, the Company intends to complete process and impact evaluations on a two to three years cycle for each program in the demand side management portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Low Income Weatherization – Schedule 21

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Low Income Weathization			
Gross kWh/Year Savings (at Site)		194,919	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$	29,263	Annual costs 2009
Incentives	$	168,557	Annual costs 2009
Total Utility Costs	$	197,820	Annual costs 2009
Total Participant Costs		NA	There are no participant costs for this program.
Net To Gross Ratio		1.00	Low income support. NTG assumed to be 1.0
Measure Life (Years)		30	Various Lives By Measure - 2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
2008 IRP Decrement Load Shape			East Side Residential Whole House

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0479	$184,190	$278,922	$94,732	1.514
Total Resource Cost Test (TRC) No Adder	0.0479	$184,190	$253,566	$69,376	1.377
Utility Cost Test (UCT)	0.0479	$184,190	$253,566	$69,376	1.377
Rate Impact Test (RIM)		$364,678	$253,566	($111,112)	0.695
Participant Cost Test (PCT)		$0	$277,498	$277,498	n/a
Lifecycle Revenue Impacts ($/kWh)				$0.0000010946	

Measure Group Inputs and Assumptions:

kWh Savings - Measures	Kwh Savings	Source
Weatherization	2,153	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
CFLs (number of households)	54.8	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
Refrigerators	1,510	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
Hot Water Measures	397	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)

Measure Economic Life - Measures	Measure Life (Years)	Source
Weatherization	30	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
CFLs (number of households)	9	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
Refrigerators	19	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
Hot Water Measures	9	2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)

Initial Planning Assumptions and analysis completed in 2005	*2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision* (8/22/05)
Cost Effectiveness Analysis completed in 2006	*Idaho Low Income Program Cost Effectiveness Analysis* - Quantec August 30, 2006.

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company intends to conduct a program evaluation during 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Energy FinAnswer – Schedule 125

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Energy FinAnswer			
Gross kWh/Year Savings (at Site)		1,494,547	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$	207,192	Annual costs 2009
Incentives	$	151,234	Annual costs 2009
Total Utility Costs	$	358,426	Annual costs 2009
Total Participant Costs	$	416,144	Incremental costs incurred by consumers based on receipts provided.
Net To Gross Ratio		0.80	Planning estimate from program inception *Energy FinAnswer Market Assessment for PacifiCorp's Idaho Service Territory Preliminary Findings* - Nexant, May 25, 2005. DEER All Other Residential Programs, 2005.
Measure Life (Years)		15	*Energy FinAnswer Market Assessment for PacifiCorp's Idaho Service Territory Preliminary Findings* - Nexant, May 25, 2005. Consistent with experience in other markets.
2008 IRP Decrement Load Shape			East Side System

Savings Calculations and Reporting:

Savings reported for the Energy FinAnswer program are based on project and measure specific verified savings. Preliminary engineering savings and costs estimates are completed during project scoping by a pre-qualified third party energy engineering firm working under contract with the company. Savings and costs are further refined into an energy analysis completed by the same firm. Once the customer installs and commissions (if required) the project, a post-installation inspection is conducted and the savings are re-calculated for each project. Incentives are then paid on final inspected savings amounts.
Measure costs are gathered from customer invoices.

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company has initiated a process and impact evaluation for the program for program year 2008. Results of those evaluations are expected to be complete in the second quarter of 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Rocky Mountain Power conducted a competitive bidding process and selected The Cadmus Group to perform the evaluations. No evaluation expenses were incurred for this effort in 2009. The Company considers evaluation costs resulting from a competitive bidding process to be confidential. The Company will provide confidential evaluation cost information to the Commission and Commission Staff under signed protective agreements.

In the future, the Company intends to complete process and impact evaluations on a two to three years cycle for each program in the demand side management portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

FinAnswer Express – Schedule 115

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - FinAnswer Express			
Gross kWh/Year Savings (at Site)		838,395	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$	173,784	Annual costs 2009
Incentives	$	81,320	Annual costs 2009
Total Utility Costs	$	255,104	Annual costs 2009
Total Participant Costs	$	243,676	Actual customer costs incurred based on project close-out documentation (invoices) - less any adjustments (if necessary) for baseline equipment.
Net To Gross Ratio		0.96	Planning estimate from program inception (2006) - FinAnswer Express Market potential Assessment for PacifiCorp's Idaho Service Territory - Nexant, August 22, 2005.
Measure Life		13	*FinAnswer Express Market characterization for PacifiCorp's Idaho Service Territory* - Nexant, August 22, 2005 which used 15 years overall. Life shortened to 13 year on program basis to account for some measures such as occupancy sensors with shorter life.

(Note: For cost effectiveness, Total Utility Costs were adjusted by ($8,800) to account for incentives booked to the balancing account that were not associated with 2009 savings)

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0577	$379,621	$607,387	$227,766	1.600
Total Resource Cost Test (TRC) No Adder	0.0577	$379,621	$552,170	$172,549	1.455
Utility Cost Test (UCT)	0.0361	$237,527	$552,170	$314,643	2.325
Rate Impact Test (RIM)		$744,677	$552,170	($192,506)	0.741
Participant Cost Test (PCT)		$142,095	$595,611	$453,517	4.192
Lifecycle Revenue Impacts ($/kWh)				$0.0000042419	

Measure Group Inputs and Assumptions:

Lighting	Value	Source and Notes
Gross kWh/Year Savings (at Site)	748,891	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 155,231	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 71,595	Annual costs 2009
Total Utility Costs	$ 226,826	Annual costs 2009
Total Participant Costs	$ 228,259	Retrofit lighting costs are based on actual customer costs. New construction lighting costs are deemed based on a combination of vendor surveys and third party data.
Net To Gross Ratio	0.96	*FinAnswer Express Market potential Assessment for PacifiCorp's Idaho Service Territory* - Nexant, August 22, 2005.
Measure Life (Years)	13	*FinAnswer Express Market characterization for PacifiCorp's Idaho Service Territory* - Nexant, August 22, 2005 which used 15 years overall. Life shortened to 13 year on program basis to account for some measures such as occupancy sensors with shorter life.
2008 IRP Decrement Load Shape		East Side Commercial Lighting

Non-Lighting	Value	Source and Notes
Gross kWh/Year Savings (at Site)	89,504	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 18,553	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 9,725	Annual costs 2009
Total Utility Costs	$ 28,278	Annual costs 2009
Total Participant Costs	$ 15,417	Measures receiving custom incentives are actual costs. Motors and HVAC are deemed costs from a combination of vendors and third party data.
Net To Gross Ratio	0.96	*FinAnswer Express Market potential Assessment for PacifiCorp's Idaho Service Territory* - Nexant, August 22, 2005.
Measure Life (Years)	13	*FinAnswer Express Market characterization for PacifiCorp's Idaho Service Territory* - Nexant, August 22, 2005 which used 15 years overall. Life shortened to 13 year on program basis to account for some measures such as occupancy sensors with shorter life.
2008 IRP Decrement Load Shape		East Side System

Cost Effectiveness Inputs at the Measure Level:

The FinAnswer Express program includes savings estimates values for a wide range of prescriptive measures including lighting, motors, HVAC equipment, and shell measures. In addition, the program includes a provision to calculate a custom incentive for measures without a prescriptive incentive.

The basis for the savings estimates for this program is the *FinAnswer Express Market Potential Assessment for PacifiCorp's Idaho Service Territory*, dated August 22, 2005 and prepared by Nexant, Inc. This document was provided in the original 2005 program filing.

The savings estimates from the Nexant work are the basis for several savings calculations tools used to manage the Idaho FinAnswer Express program. Lighting savings contributed approximately 90% of the program results in 2009. The lighting tool is an Excel based tool built and maintained by the program staff that includes deemed wattages by fixture types for both baseline and replacement fixtures. Baseline (pre) and post fixture counts along with hours of operation are input on a project specific basis. For each project, the lighting tool calculates energy and average demand savings, incentives, the value of energy and demand savings, simple paybacks with and without incentives, counts of replaced fixture by type and several other project specific metrics.

Savings from NEMA premium motors are calculated using a spreadsheet based tool referencing deemed energy and capacity values based on horsepower size and sector (i.e., commercial and industrial). These values are derived from efficiency gains and operating hour assumptions.

Savings from mechanical and other energy efficiency measures are calculated in a manner similar to motors.

Cost effectiveness inputs included in this section are the aggregations of savings and expenditures in two large categories – lighting and non-lighting.

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company has initiated a process and impact evaluation for the program for program years 2006 to 2008. Results of those evaluations are expected to be complete in the second quarter of 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Rocky Mountain Power conducted a competitive bidding process and selected The Cadmus Group to perform the evaluations. No evaluation expenses were incurred for this effort in 2009. The Company considers evaluation costs resulting from a competitive bidding process to be confidential. The Company will provide confidential evaluation cost information to the Commission and Commission Staff under signed protective agreements.

In the future, the Company intends to complete process and impact evaluations on a two to three years cycle for each program in the demand side management portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Agricultural Energy Services (Irrigation Energy Savers) – Schedule 155

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Agricultural Energy Services (Irrigation Energy Savers)		
Gross kWh/Year Savings (at Site)	3,994,349	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 416,641	Annual costs 2009
Incentives	$ 390,597	Annual costs 2009
Total Utility Costs	$ 807,238	Annual costs 2009
Total Participant Costs	$ 1,437,654	Combination of deemed and actual costs depending on the measure type.
Net To Gross Ratio	0.75	*Review and Development of Utah Power's Irrigation Program In Idaho* - Fazio Engineering, August 31, 2005.
Measure Life		At program level, it is a weighted average of the measure group inputs.

All Measures				AC: IRP 16% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0979	$1,479,946	$1,271,470	($208,476)	0.859
Total Resource Cost Test (TRC) No Adder	0.0979	$1,479,946	$1,155,881	($324,064)	0.781
Utility Cost Test (UCT)	0.0497	$751,618	$1,155,881	$404,263	1.538
Rate Impact Test (RIM)		$1,722,272	$1,155,881	($566,391)	0.671
Participant Cost Test (PCT)		$728,328	$1,112,186	$383,858	1.527
Lifecycle Revenue Impacts ($/kWh)				$0.0000124803	

Equipment Exchange and Pivot/linear Upgrades	Value	Source and Notes
Gross kWh/Year Savings (at Site)	2,564,171	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 267,463	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 203,923	Annual costs 2009
Total Utility Costs	$ 471,386	Annual costs 2009
Total Participant Costs	$ 416,144	Combination of deemed measure costs based on Fazio work and actual customer costs submitted with applications.
Net To Gross Ratio	0.75	*Review and Development of Utah Power's Irrigation Program In Idaho* - Fazio Engineering, August 31, 2005.
Measure Life (Years)	4	*Review and Development of Utah Power's Irrigation Program In Idaho* - Fazio Engineering, August 31, 2005.
2008 IRP Decrement Load Shape		East Side Commercial Cooling

System Upgrades	Value	Source and Notes
Gross kWh/Year Savings (at Site)	1,430,178	Annual results 2009 (Gross at Site)
Program Management and Administration Costs	$ 149,178	Allocated percentage (based on kWh contribution) of non -incentive costs for 2009.
Incentives	$ 186,674	Annual costs 2009
Total Utility Costs	$ 335,852	Annual costs 2009
Total Participant Costs	$ 1,021,510	Actual customer costs incurred based on project close-out documentation (invoices) - less any adjustments (if necessary) for baseline equipment.
Net To Gross Ratio	0.75	*Review and Development of Utah Power's Irrigation Program In Idaho* - Fazio Engineering, August 31, 2005.
Measure Life (Years)	12	*Review and Development of Utah Power's Irrigation Program In Idaho* - Fazio Engineering, August 31, 2005. Planning value was 7 years. Based on project types receiving incentives in this category - major equipment, piping and variable frequency drives which are similar in type and measure life to Energy FinAnswer, the measure life for these measures was adjusted to an approximate mid-point between 7 years and 15 years (Energy FinAnswer measure life) and was set at 12 years.
2008 IRP Decrement Load Shape		East Side Commercial Cooling

Cost Effectiveness Inputs at the Measure Level:

Measure level savings estimates for prescriptive measures for the Irrigation Energy Savers program are based on the *Review and Development of Utah Power's Irrigation Program in Idaho,* prepared by Fazio Engineering on August 31, 2005.

For projects that are not eligible for prescriptive incentive, savings are estimated at the site utilizing program funded engineering.

The Company aggregates savings and incentives for reporting at the program level.

Cost effectiveness inputs included in this section are the aggregations of savings and expenditures in two large categories – Equipment Exchange and Pivot/Linear Upgrades (including nozzles, gaskets, drains, and pivot/linear equipment upgrades) and System Upgrades (including system analysis). These groupings are utilized to reflect similar measure lives.

Cost Effectiveness Results:

For discussion of the cost effectiveness results for the program and recommendations for potential modifications, please see Agricultural Energy Services program section in the body of the Idaho DSM Annual Report.

Process and Impact Evaluation

No process or impact evaluations were completed during 2009. The Company has initiated a process and impact evaluation for the program for program years 2006 to

2008. Results of those evaluations are expected to be complete in the third quarter of 2010.

The Company did not make any program modifications as a result of process or impact evaluations during 2009.

Rocky Mountain Power conducted a competitive bidding process and selected The Cadmus Group to perform the evaluations. No evaluation expenses were incurred for this effort in 2009. The Company considers evaluation costs resulting from a competitive bidding process to be confidential. The Company will provide confidential evaluation cost information to the Commission and Commission Staff under signed protective agreements.

In the future, the Company intends to complete process and impact evaluations on a two to three years cycle for each program in the demand side management portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Irrigation Load Control Program – Schedules 72 and 72A

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Irrigation Load Control		Value	Source and Notes
Total kW Under Load Control (All contracts)		258,355	2009 ID Load Control Quantitative Review
Average kW Dispatched during irrigation season (At Site)		247,050	2009 Calculation based on Average Dispatch (consistent with incentive calculation) - Cadmus 2009
Benefit Value of Dispatched kW (At Site)	$	73.09	2009 Value as determined by agreed upon Valuation Methodology (see notes below) - 2008 IRP
Benefit Value of Dispatched kW (At Generation)	$	81.56	2008 IRP Value Grossed up for 10.392% Line Losses
Benefit Value = Avg kW Distpatched multiplied by $81.56	$	20,149,384	Calculation ($81.56 $/kW * 247,050 kW-Yr)
Program Management and Administration Costs	$	3,816,417	Annual costs 2009
Incentives	$	7,298,531	Annual costs 2009 - Less $25,946 of 2008 incentives paid in 2009
Total Utility Costs	$	11,114,948	Annual costs 2009
Total Participant Costs		NA	There are no direct participant costs for the program.
Net To Gross Ratio		1.00	Assume 1.0 Net To Gross
Measure Life (Years)		10	Benefit value is NPV of 10 year benfits from avoided generation and market purchases.

Notes:

For further background on 2009 program perfromance see "2009 ID Irrigation Quantitative Review.doc" dated November 14, 2009
For further background on the valuation methodology, please refer to "Proposed Valuation Methodology for the Idaho Irrigation Load Control Program" that was produced as part of a stipulated settlement with the Idaho Irrigation Pumpers' Association on Nov. 5, 2007.

2009 Irrigation Load Control

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost
Total Resource Cost Test (PTRC) + Conservation Adder		$3,816,417	$22,164,322	$18,347,905	5.808
Total Resource Cost Test (TRC) No Adder		$3,816,417	$20,149,384	$16,332,967	5.280
Utility Cost Test (UCT)		$11,114,948	$20,149,384	$9,034,436	1.813
Rate Impact Test (RIM)		$11,114,948	$20,149,384	$9,034,436	1.813
Participant Cost Test (PCT)		$0	$7,298,531	$7,298,531	n/a
Lifecycle Revenue Impacts ($/kWh)					

Reporting Period Changes

Please note that the costs included in this DSM Annual Report and the tables above reflect cost associated with the Calendar Year 2009, while the costs included in the *2009 ID Irrigation Quantitative Review* reflect costs for the Seasonal Report that runs from October 1, 2008 to September 30, 2009. Operational results and savings are consistent between reports because the load control season occurs during June through August of each year.

Therefore, results included in this Annual Report reflect the operations/savings and costs for the Calendar year 2009. Cost Effectiveness was reevaluated to reflect the difference in period costs. For calculation of cost effectiveness, program incentive expenses were reduced by $25,946 to reflect incentive payments made during calendar year 2009 for 2008 program participation.

Program costs reflected in this annual report are $460,284 higher than those reflected in the *2009 ID Irrigation Quantitative Review*, while the operational results and associated savings and benefits are identical between reports. As a result, the cost effectiveness test results are slightly lower in this annual report than those reported in the *2009 ID Irrigation Quantitative Review*.

Beginning in Calendar Year 2010, the Idaho Irrigation Load Control Report (or *ID Irrigation Quantitative Review*) will reflect calendar year results and costs and will be included with the 2010 DSM Annual Report.

Cost Effectiveness Inputs

Program kW savings are calculated based on the aggregation of individual meters with load control equipment (both scheduled and dispatchable). Savings per meter are calculated as average irrigation usage over the past 24 months. Curtailments/dispatch events are logged to indentify all meters that were dispatched during an event to develop the total amount dispatched.

For benefit determination, The Cadmus Group utilizes a simplified excel model to develop a weighted average monthly dispatch for the irrigation season (247,050 kW for 2009). This amount is then multiplied by the value per kW as determined by the *Proposed Valuation Methodology for the Idaho Irrigation Load Control Program* dated November 5, 2007. The value for 2009 is $73.09/kW-yr at site, or $81.56/kW-yr at generation including 10.392% line losses.

Program Evaluation

Rocky Mountain Power has provided an annual report (or *ID Irrigation Quantitative Review*) of the activities and results of the Idaho Irrigation Load Control Program to the Idaho Commission each year since the program started in 2003. These results reflect the measured actual dispatch and impact on the system. The annual reporting approach utilizes a workplan similar to those used by third party evaluation firms and serves as an annual program evaluation.