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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION FOR APPROVAL OF CHANGES TO THE IRRIGATION PEAK REWARDS PROGRAM, AND FOR AUTHORITY TO RECOVER THE COST OF THE PROGRAM IN THE PCA	)	CASE NO. IPC-E-08-23

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

Q. Please state your name and business address.

A. My name is Timothy E. Tatum and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Company") as the Manager of Cost of Service in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Economics from Boise State University in 2001. In 2005, I earned a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses including "Practical Skills for the Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities; "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc.; and Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company in 1996 as a Customer Service Representative in the Company's

Customer Service Center. In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I maintained proper accounting for Demand-Side Management ("DSM") expenditures, prepared and reported DSM program accounting and activity to management and various external stakeholders, conducted cost-benefit analyses of DSM programs, and provided DSM analysis support for the Company's 2004 Integrated Resource Plan ("IRP").

In August of 2004, I accepted a position as a Pricing Analyst in Pricing and Regulatory Services. As a Pricing Analyst, I provided support for the Company's various regulatory activities, including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

In August of 2006, I was promoted to Senior Pricing Analyst. As a Senior Pricing Analyst, my responsibilities were expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies. I prepared the Company's cost-of-service studies submitted as part of Case Nos. IPC-E-07-08 and IPC-E-08-10 and served as the Company's cost-of-service witness in both cases.

In September of 2008, I was promoted to Manager of Cost of Service. As Manager of Cost of Service I oversee the Company's cost-of-service activities, such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will describe in detail a number of proposed changes to the Irrigation Peak Rewards Program, Schedule 23.

Q. Please provide an overview of the current Irrigation Peak Rewards Program.

A. The Irrigation Peak Rewards Program, Schedule 23 (the "Program") is a voluntary load control program currently available to agricultural irrigation customers with irrigation pumps having a cumulative horsepower rating of 75 or greater. The purpose of the Program is to produce a decrease in the Company's system summer peak load by turning off specified irrigation pumps between the hours of 4:00 P.M. and 8:00 P.M. on either one, two, or three weekdays per week during the months of June, July, and August.

Under the Program, the Company turns off specified irrigation pumps on the customer's side of a metered service point ("Metered Service Point") during summer weekdays with the use of an electric switch ("Timer"). In exchange for allowing the Company to turn off specified irrigation pumps, participating Customers receive a monthly monetary incentive ("Demand Credit") paid on the basis of the kilowatt ("kW") reduction as measured by the customer's monthly Billing Demand.

Q. Did the Company develop the proposed changes to the Program with input from parties external to Idaho Power?

A. Yes. As part of the settlement Stipulation in Case No. IPC-E-07-08, approved by the Idaho Public Utilities Commission ("IPUC" or "the Commission") on February 28, 2008, through Order No. 30508, all parties to that matter agreed that, prior to June 19, 2008, the Company would convene a working group ("Workshop") where interested parties would discuss potential modifications to the Program and related issues.

Consistent with the Commission's Order, on June 11, 2008, the Company hosted the Workshop at its Mini-Cassia office in Heyburn, Idaho. Attendees of the Workshop included representatives of the Idaho Irrigation Pumpers Association ("IIPA"), Idaho Power agricultural irrigation customers, Commission Staff, and Company representatives.

Q. What were the specific objectives of the Workshop according to the settlement Stipulation in Case No. IPC-E-07-08?

A. According to the terms of the Stipulation, the purpose of the Workshop would be to discuss (1) the operation and results of the current Program, (2) the design and implementation of a dispatchable demand response pilot program for the 2009 irrigation season, (3) the methodology used in determining the amount of the incentive payments for both the Program and the dispatchable pilot program, (4) possible improvements to the joint marketing efforts that could improve participation in the demand response programs, and (5) possible additional steps needed to ensure that the effects of the irrigation demand response programs are adequately reflected in Idaho Power's load research samples for the irrigation class and the system as a whole.

Q. Please summarize the issues discussed at the Workshop.

A. The Company began the Workshop by providing a brief review of the Program's operational results for 2007. After the Company completed its 2007 operational review, IIPA presented a number of potential modifications to the Program for the group's consideration. IIPA's first recommendation included the implementation of a dispatchable load control option for customers with pump sizes of 30 HP and above. IIPA's recommendation was modeled after the irrigation demand response program currently operated by Rocky Mountain Power in Eastern Idaho. Secondly, IIPA recommended that the Workshop attendees consider the potential of using one-way communication switches, similar to those used in the Company's residential load control program, to turn off irrigation pumps below 30 HP in size. This second option was presented as a potentially cost effective way to broaden the program's availability to include customers with smaller pump sizes.

Following IIPA's presentation, Idaho Power presented a proposal for a dispatchable load control program design. In its presentation, the Company detailed the process that was used to evaluate potential program designs, including the economic and operational considerations that guided the analysis process.

Q. Did the Workshop include a discussion of possible improvements to the joint marketing efforts of the Company and IIPA to improve participation in the Program?

A. Yes. The Workshop attendees discussed several possible modifications to the marketing efforts for the Program. These discussions ultimately led to an enhanced marketing strategy that includes an enhanced commitment from IIPA to actively encourage its membership to participate in the Program. I will discuss the Company's role in the enhanced marketing strategy in greater detail later in my testimony.

Q. Did the Workshop include a discussion of possible additional steps needed to ensure that the effects of the irrigation demand response programs are adequately reflected in Idaho Power's load research samples for the irrigation class and the system?

A. Yes. During the Workshop, the Company presented the steps it has taken to modify the method used to derive the coincident peak demand values that better reflect the impact that the Program has on the Company's peak demands. Idaho Power uses load research data to develop the class coincident peak demands for the customer classes that do not have interval metering capabilities. Class coincident demands are used to allocate demand-related costs in the Company's class cost-of-service studies. The new method of deriving class coincident peak demands was subsequently applied in the class cost-of-service study prepared as part of the Company's 2008 general rate case proceeding, Case No. IPC-E-08-10.

Q. Was there a consensus reached or action items assigned at the conclusion of the Workshop?

A. Yes. Following the presentations by the Company and IIPA, attendees of the Workshop openly discussed the proposed Program modifications. The group ultimately came to agreement that a properly designed dispatchable irrigation demand response program had significant potential to cost-effectively reduce peak demand and, if implemented, would be in the public's interest. At the conclusion of the Workshop, the Company agreed to research and analyze the set of recommended Program design options to verify viability and cost effectiveness. Furthermore, the Company agreed to discuss with IIPA and Staff its findings and recommendations upon completion of such research and analysis prior to making a filing with the Commission.

Q. Did the Company fulfill its commitment to engage the IIPA and Commission Staff in the research and analysis process following the Workshop?

A. Yes. In the weeks following the Workshop, the Company engaged in an iterative research and analysis process involving IIPA and the Commission Staff that included two phone conference workshops. These efforts ultimately led to the parties indentifying and agreeing upon a revised Program design. The Company shared plans for a revised Program with the Energy Efficiency Advisory Group ("EEAG") at the October 2, 2008, meeting and received comments and general support for the recommendations from the EEAG. The proposed modifications that emerged from this cooperative approach will serve to increase both the cost-effective load reduction and broader availability of the Program.

Q. Please provide an overview of the proposed modifications to the Program that resulted from the collaborative Workshop process?

A. The Workshop and subsequent collaborative research and analysis process resulted in the following proposed modifications: (1) the addition of a set of dispatchable interruption options that will allow the Company to remotely dispatch service interruptions to participating irrigation pumps, (2) a broadened availability of the Program that will provide the vast majority of agricultural irrigation customers the opportunity to participate, (3) a reduction in the number of weeks over which the Program is operated annually from the three summer months of June through August to a six week period, June 15 through July 31 ("Program Season"), and (4) a modified incentive structure that aligns with the new Program's design.

Q. Please describe the proposed set of dispatchable interruption options that will allow the Company to remotely dispatch service interruptions to participating irrigation pumps.

A. There are three separate dispatchable interruption options proposed as part of the revised Program. Under the first dispatchable interruption option, Dispatchable Option 1, the Company will install a dispatchable one-way communication load control device that will be connected to the electrical panel(s) servicing the irrigation pumps associated with the Metered Service Points enrolled in the Program. The Load Control Device utilized under Dispatchable Option 1 will provide the Company the ability to send a signal that will interrupt or not allow the associated irrigation pumps to operate during dispatched load control events. Dispatchable Option 1 is designed to appeal to customers with smaller pump sizes; however, there is no pump-size restriction under this option.

Under the second dispatchable interruption option, Dispatchable Option 2, the Company will install a dispatchable load control device capable of two-way communication that will be connected to the electrical panel(s) servicing the irrigation pumps associated with the Metered Service Points enrolled in this Program. The load control device utilized under Dispatchable Option 2 will provide the Company and the Customer remote control and monitoring of the associated irrigation pumps. Under this option, the Company will use this technology to send a signal that will interrupt or not allow the irrigation pumps to operate during dispatched load control events. As with Dispatchable Option 1, there is no pump-size restriction under this option. The Company expects that the majority of participating customers will choose to participate under Dispatchable Option 2.

The third dispatchable interruption option, Dispatchable Option 3, is a dispatchable interruption option available only to customers with metered service points with interval metering having more than one pump and at least 1,000 cumulative HP. Under this Dispatchable Option, eligible Customers can choose to either (1) have service interrupted using a dispatchable two-way communication Load Control Device, as in Dispatchable Option 2, or (2) manually interrupt electric service to participating irrigation pumps during load control events.

Q. How will the availability of the Program be broadened under proposed Program design?

A. The vast majority of agricultural irrigation customers will have the opportunity to participate in the revised Program. The current Program is available only to agricultural irrigation customers with irrigation pumps having a cumulative horsepower rating of 75 or greater. Under the proposed Program design, all pumps sizes will be eligible for participation.

Q. What is the rationale for allowing all pumps sizes to become eligible for participation in the Program?

A. During the Workshop discussions, the IIPA and other agricultural irrigation customers expressed their desire to work toward broadening the availability of the Program to increase participation and maximize cost-effective load reduction. Two recommendations surfaced as potentially viable options. The first recommendation included expanding the Program eligibility criteria to allow participation by customers with irrigation pumps having a cumulative horsepower rating of below 75 HP ("Small Pumpers"). The second recommendation involved adding additional flexibility into to the Program to enable more customers with very large irrigation systems of 1,000 HP and greater to participate ("Large Pumpers").

Q. Why does the current Program prohibit participation by customers with irrigation pumps having a cumulative horsepower rating of below 75 HP?

A. The provision to exclude Small Pumpers from participation in the Program has historically been driven by economics. The Company's past economic analyses have shown that pumps below approximately 100 HP are not cost-effective additions to the Program from a utility cost perspective. That is, the fixed investment required for participation in the Program cannot be adequately offset by the relatively low load reduction benefits provided by these smaller irrigation systems. In order to maintain the cost effectiveness of the current Program, an Installation Fee of $250.00 is assessed to those customers with irrigation pumps between 75 and 99 cumulative horsepower per Metered Service Point. Consistent with this approach, the following expanded Installation Fee schedule is proposed:

Horsepower (HP)	Dispatchable Option			Timer Option
	1	2	3 *	
Less than 30 HP	$500	$1,000	N/A	$500
From 30 to 49 HP	$0	$500	N/A	$350
From 50 to 74 HP	$0	$0	N/A	$350
From 75 to 99 HP	$0	$0	N/A	$250
Greater than 99 HP	$0	$0	N/A	$0

Note: (*) An Installation Fee will not be assessed under Dispatchable Option 3.

The proposed Installation Fee structure will allow more customers to become eligible for participation in the Program while maintaining its cost effectiveness.

Q. Do the current Program provisions explicitly restrict Large Pumpers from participation?

A. No. The current Program does not explicitly restrict Large Pumpers from participation; however, the complexity of these large, multiple-pump irrigation systems often prohibits an interruption of service to all the pumps served by a single Metered Service Point, which is required under the provisions of the current Program. The proposed Dispatchable Option 3 provides an opportunity for the Large Pumpers to participate in the Program by allowing them the flexibility to choose which irrigation pumps will be interrupted during each dispatched load control event.

Q. Why is the Company proposing to reduce the number of weeks over which the Program is operated annually?

A. As part of the research and analysis process that led to the proposed Program design, the internal Program design team at Idaho Power held several discussions with subject matter experts that work within the generation dispatch and power supply planning functions of the Company. According to perspectives shared by representatives from the generation dispatch and power supply planning groups, the value of the load reduction capability of the Program is in its ability to reduce loads when the demand on the electrical system is at or near the annual system peak. Furthermore, these discussions confirmed that currently there is a near zero probability that Idaho Power's electrical system will experience a annual system peak demand outside of the time period of June 15 through July 31. With that in mind, the Program Season was revised to align with the June 15 through July 31 period.

Q. How will the incentive payments be calculated under each dispatchable interruption option?

A. Under the dispatchable interruption options, customers will receive a financial incentive in the form of a bill credit applied to the monthly bills during June and July for each Metered Service Point enrolled in the Program. The bill credit will include a demand-based component ("Demand Credit") and an energy-based component ("Energy Credit"). Under Dispatchable Options 1 and 2, the Demand Credit will be based upon the monthly Billing Demand, as measured in kW. The Energy Credit provided under these options will be based upon the monthly energy usage, as measured in kWh, for the associated Billing

Period. Under Dispatchable Option 3, the Demand Credit will be based upon the monthly Billing Demand minus the average demand, as measured in 15 minute intervals, during each load control event initiated during a Billing Period. The Energy Credit under this option will be based upon a calculated value, as measured in kWh. The energy basis for Energy Credit will be calculated separately for each Billing Period by multiplying the calculated kW amount used in the Demand Credit calculation by the ratio of the monthly energy usage to the Billing Demand for the associated Billing Period.

Q. How does the proposed incentive structure differ from the current incentive structure?

A. Under the current Program design, incentives are paid on a demand basis only according to the following schedule:

Timer Option	Demand Credit ($/kW)
One Weekday	$2.01
Two Weekdays	$3.36
Three Weekdays	$4.36

Under the proposed Program design, incentives would be paid on a demand basis and an energy basis (except for the "One Weekday" Timer Option, which is paid on demand basis only) according to the following schedule:

Dispatchable Options		
Dispatchable Option	Demand Credit ($/kW)	Energy Credit ($/kWh)
1	$ 4.65	$ 0.031
2	$ 4.65	$ 0.031
3	$ 4.65	$ 0.031
Timer Options		
Timer Option	Demand Credit ($/kW)	Energy Credit ($/kWh)
One Weekday	$ 3.15	$ 0.000
Two Weekdays	$ 4.65	$ 0.002
Three Weekdays	$ 4.65	$ 0.007

Q. Why does the proposed incentive structure include the addition of an energy-based incentive amount?

A. Since the inception of the Program, the Company has maintained that it is important that the Demand Credit amount remain below the Demand Charge under Schedule 24, Agricultural Irrigation Service. This ensures that customers participating in the Program are not incented to turn on a pump when they otherwise would not simply to earn a bill credit. The proposed incentive structure recognizes that notion by including an energy-based incentive amount which allows for additional incentive dollars to be provided to participating customers while maintaining a Demand Credit at or below the current Demand Charge under Schedule 24.

Q. What is the justification for the increased incentive amounts under the proposed incentive structure?

A. As discussed earlier in my testimony, the value of this Program is in its ability to reduce loads when the demand on the electrical system is at or near the annual system peak. In other words, this Program allows the Company to defer or avoid the procurement of additional generation capacity to serve peak demand. Consistent with that concept, the cost basis for the incentive payments provided under the Program is the levelized cost per annual kW of a simple-cycle combustion turbine. Because the monthly incentive payments are based upon the annual avoided capacity cost, the reduced Program Season requires a larger monthly incentive payment in order to pay the same annual incentive amount. Furthermore, the potential average load reduction of the Program during the reduced Program Season is greater as the Program Season is concentrated into a period when irrigation loads are at their highest.

Q. Has the Company performed an analysis to determine that the proposed Program design is cost effective?

A. Yes. The economic analysis that ultimately led to the modified Program design, including the proposed incentive structure, is detailed on Exhibit No. 1. Exhibit No. 1 is a memorandum from Pete Pengilly, Idaho Power Customer Research and Analysis Leader, that describes the methodology used to determine that the proposed Program is cost effective. The memorandum details the underlying assumptions and financial inputs used in the analysis as well as the analysis results.

Q. Under the proposed Dispatchable Options, are customers permitted to opt-out of an individual load control event without having to completely terminate participation in the Program?

A. Yes. Customers selecting Dispatchable Options 1 and 2 may opt-out of a load control event up to five times per season any time prior to or during a load control event. Each time a customer chooses to opt-out of a load control event a fee of $0.005 per kWh will be assessed based upon the current month's energy usage. Under Dispatchable Option 3, customers may opt-out of a load control event at any time. However, due to the nature of the bill credit calculation under Dispatchable Option 3, customers choosing to opt-out of a load control event will cause the average demand during load control events to increase, thereby, reducing the monthly bill credit amount.

Q. Is the Company proposing any changes to the Timer Option under the Program?

A. No. Aside from shortening the Program Season and the associated change in the incentive structure as described earlier in my testimony, the mechanics of the Timer Option will remain unchanged.

Q. If the Commission approves the proposed modifications to the Program, how does the Company plan to communicate the new Program design to eligible customers?

A. The Company plans to solicit participation in the Program for the 2009 Program Season using a number of methods. First, information packets will be mailed to all agricultural irrigation customers explaining the Program in detail and inviting them to participate. This packet of information will be customized for each customer and will include a listing of the customer's eligible Metered Service Points and an estimate of the potential incentive amount for each Metered Service Point based on the associated 2008 bill history. Second, Idaho Power, in conjunction with county extension services and other irrigation/agricultural entities, will sponsor 7 to 10 irrigation workshops across the Company's service territory. The Peak Rewards program will be one of the specific topics covered. These workshops will present details of how the incentives are calculated, demonstrate how the equipment works, and how customers will be able to operate their irrigation pumps using the equipment. Third, Idaho Power's local agricultural representatives will be available to answer questions and help market the Program on an ongoing basis. Finally, Idaho Power will advertise the Program in various agricultural publications throughout the winter and early spring to raise awareness and to inform customers of the Program.

Q. You mentioned that the Company plans to educate customers on the benefits of the revised Program at workshops over the winter months. Does the Company plan to market the revised Program prior to the Commission issuing an Order on this matter?

A. No. The Company plans to initiate the proposed Program marketing strategy immediately following the issuance of the Commission's Order in this proceeding. Should the Commission approve the settlement Stipulation, an Order issued by January 2, 2009, would allow adequate time to effectively market the Program prior to the 2009 Program Season.

Q. What impact are the proposed modifications expected to have on the Program's ability to cost effectively reduce peak demand?

A. In 2009, the Program is expected to provide and overall peak load reduction of approximately of 144 MW (including losses). The Company estimates that 800 Metered Service Points will be enrolled in the Dispatchable Options resulting in a peak load reduction of about 128 MW (including losses). Idaho Power estimates that the number of Metered Service Points enrolled in the Timer Option will decrease to 375 resulting in a peak load reduction of approximately 16 MW (including losses). The overall increase in peak load reduction expected in 2009 due to the proposed Program modifications is estimated to be 108 MW (including losses).

Q. Is the Company planning to test the effectiveness of the proposed Dispatchable Options on a pilot basis in 2009?

A. No. The Dispatchable Options are proposed as permanent additions to the current Schedule 23, Irrigation Peak Rewards Program. However, to ensure that the installation of the load control devices can be completed prior to the start of the Program Season, the Company proposes to limit participation under the Dispatchable Options to 1,000 Metered Service Points in 2009.

Q. Do you expect the proposed participation limit to negatively impact the Program's potential to reduce peak loads in 2009?

A. No. As detailed earlier in my testimony, the Company estimates participation under the Dispatchable Options to be approximately 800 Metered Service Points in 2009. Therefore, limiting participation to 1,000 Metered Service Points is not expected to impact the Program's potential to reduce peak loads in 2009.

Q. Have you prepared a revised Schedule 23, Irrigation Peak Rewards Program, which reflects the proposed modifications to the Program?

A. Yes. Included as Exhibits A and B to the settlement Stipulation in this proceeding is a revised Schedule 23, Irrigation Peak Rewards Program, in legislative and final format.

Q. What are the projected costs of the proposed Program over the next three years, 2009 through 2011?

A. Idaho Power estimates the Program will grow from an estimated 800 Metered Service Points in the first year to approximately 1,400 in the third year. The following table details the projected annual Program costs over the period of 2009 through 2011.

Year	Idaho Power Labor	Equipment & Install Labor	Other Program Admin.	Incentives	Total
2009	$ 110,000	$ 1,485,000	$ 230,000	$ 4,864,000	$ 6,689,000
2010	$ 113,000	$ 557,000	$ 302,000	$ 8,575,000	$ 9,547,000
2011	$ 117,000	$ 557,000	$ 374,000	$ 9,798,000	$ 10,846,000

Q. How does the Company propose to fund the costs associated with the modified Program?

A. Currently, this Program is funded through the Energy Efficiency Rider, Schedule 91 ("Rider"). However, the increased costs associated with the proposed Program modifications cannot be adequately funded at the current Rider funding level of 2.5 percent of base revenues. At the current level, the Rider provides approximately $17 million annually. If this Program is to be funded by the Rider, the annual funding amount would have to be increased to approximately $27 million or 4 percent of base revenues. Considering there are other planned energy efficiency activities that will demand additional Rider funding beyond the current level, Mr. Said proposes an alternative funding strategy for this Program that he describes in detail in his testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-08-23

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 1

MEMORANDUM

Date: October 22, 2008

Prepared For: Tim Tatum, Pricing and Regulatory Services

Prepared By: Pete Pengilly, Customer Relations and Energy Efficiency

Subject: Irrigation Peak Rewards,
2009 Dispatchable Program Option
Cost-Effectiveness

Idaho Power develops cost-effectives analyses for each demand response and energy efficiency program offered to its customers. The first step is to obtain the demand-side management (DSM) alternative costs from the most recent Integrated Resource Plan (IRP). The cost-effectiveness analysis for the Irrigation Peak Rewards program is based on the 2006 IRP with values corresponding with year 2009 (see figure 1, Year 4).

Figure 1. DSM alternative costs from the 2006 IRP, Technical Appendix D, page 68.

DSM Alternative Energy Cost ($/MWh)					
	Seasonal Market Price Forecast				
Year	SONP	SMP	SOFP	NSMP	NSOFP
1	$ 91.08	$ 68.57	$ 51.54	$ 77.61	$ 65.59
2	$ 95.30	$ 69.89	$ 51.61	$ 78.95	$ 65.64
3	$ 88.97	$ 65.98	$ 48.07	$ 68.96	$ 55.61
4	$ 88.12	$ 66.39	$ 48.52	$ 68.15	$ 55.39
5	$ 67.14	$ 50.43	$ 37.03	$ 52.75	$ 42.31
6	$ 67.81	$ 55.93	$ 41.28	$ 54.30	$ 42.99
7	$ 68.94	$ 67.85	$ 50.72	$ 64.61	$ 51.51
8	$ 71.25	$ 71.71	$ 54.18	$ 68.18	$ 54.33
9	$ 73.30	$ 74.02	$ 56.01	$ 70.06	$ 56.05
10	$ 75.73	$ 78.45	$ 59.19	$ 74.07	$ 59.74
11	$ 78.91	$ 82.40	$ 62.08	$ 78.96	$ 63.83
12	$ 82.37	$ 90.38	$ 66.94	$ 86.37	$ 69.54
13	$ 85.26	$ 92.36	$ 70.70	$ 90.27	$ 72.64
14	$ 89.35	$ 98.01	$ 75.25	$ 95.24	$ 76.92
15	$ 92.64	$ 102.92	$ 79.15	$ 100.11	$ 80.34
16	$ 86.04	$ 97.28	$ 75.60	$ 94.42	$ 76.63
17	$ 89.19	$ 104.05	$ 80.51	$ 101.25	$ 81.28
18	$ 93.13	$ 108.84	$ 84.94	$ 105.87	$ 85.53
19	$ 95.86	$ 114.48	$ 90.26	$ 111.23	$ 90.19
20	$ 99.47	$ 120.35	$ 96.05	$ 118.21	$ 95.55
21	$ 93.36	$ 123.96	$ 98.93	$ 121.75	$ 98.42
22	$ 97.22	$ 127.68	$ 101.90	$ 125.40	$ 101.37
23	$ 100.74	$ 131.51	$ 104.95	$ 129.17	$ 104.41
24	$ 104.46	$ 135.46	$ 108.10	$ 133.04	$ 107.55
25	$ 108.97	$ 139.52	$ 111.35	$ 137.03	$ 110.77
26	$ 110.64	$ 143.71	$ 114.69	$ 141.14	$ 114.10
27	$ 112.32	$ 148.02	$ 118.13	$ 145.38	$ 117.52
28	$ 114.01	$ 152.46	$ 121.67	$ 149.74	$ 121.04
29	$ 115.71	$ 157.03	$ 125.32	$ 154.23	$ 124.68
30	$ 117.42	$ 161.74	$ 129.08	$ 158.86	$ 128.42

Fixed plant costs were combined with the variable costs for developing total alternative costs. For the peak alternative, a 162MW Simple Cycle Combustion Turbine plant was used as the cost basis. The levelized capacity cost factors applied were $64.92/KW/year.

Next, Idaho Power inputs assumptions, costs, and financial factors into a spreadsheet model that calculates the benefits and costs to offer the Program. The cost-effectiveness provided in figure 2 is based on first year participation estimated to be 800 service locations.

Figure 2. Irrigation Peak Rewards Dispatchable Program Option Cost-Effectiveness Model

Irrigation Peak Rewards Dispatchable Program Benefit/Cost Analysis 2009	Model Inputs
DSM Capacity Alternative Cost	64.92
Line Loss (Summer on Peak)	13.00%
Line Loss	10.90%
Discount Rate	6.93%
Escalation Rate	3.00%
Program Participation (Service Locations)	800
Peak Load Reduction per Service Location (kW)	190
Realization Rate	75%
Average Peak Load Reduction (kW)	114,000
Peak Load Reduction with Line Loss (kW)	128,820
Energy Shifted (kWh)	4,560,000
Program Costs	
Equip. Installation, Administration, Maintenance (First Year)	$ 1,677,600
Administration, Promotion, Evaluation (First Year)	$ 148,000
Incentive	
Total Incentive Payments (First Year)	$ 4,864,000
Benefit/Cost Ratios	
Benefit/Cost Ratio (UC) Year 1	**1.27**

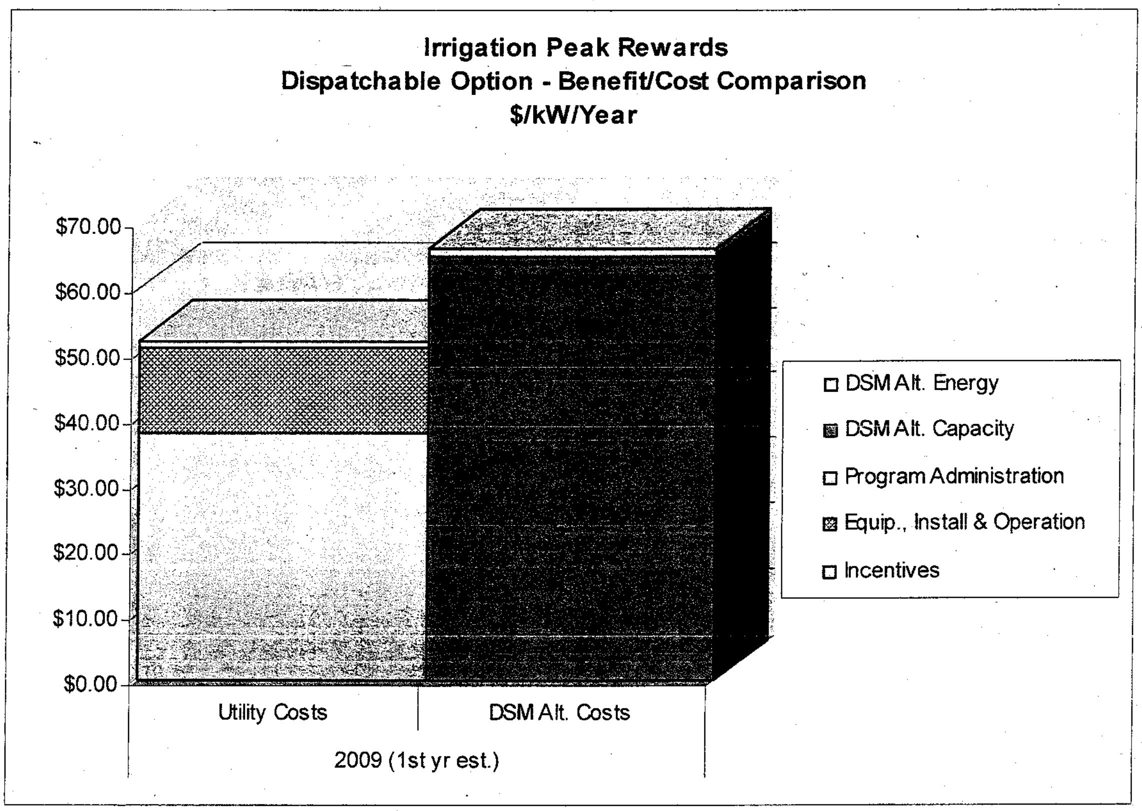
The cost-effectiveness model calculates the benefits of the Program by multiplying the expected load reduction of the Program by the DSM alternative capacity cost. Then adds the energy savings, which are grossed up for line losses and multiplied by the difference between the energy costs during the summer on peak time period and the summer off peak time period presented in figure 1.

This calculation with 800 locations and an average capacity of 190 kW per location with an estimated 75% realization (which estimates the probability that the pump is on during a control event) and 13% summer on peak line loss equals an estimated load reduction of 128 MW and a shifted energy amount of 5,152,800 kWhs. Applying the $64.92 per kW DSM alternative cost to the 128 MW peak load reduction and adding the calculated shifted energy benefit of $118,314 provides an avoided cost benefit of approximately $8.5 million.

The model calculates the total cost to the utility including: incentives, program administration and promotion, equipment installation and maintenance, and evaluation. The customer incentive of $4.65 per kW plus $0.031 per kWh for the months of June and July is the largest cost to the Program. This cost for 800 service points with an average capacity of 190 kW is estimated to equal $4,864,000. It is expected that in 2009 the equipment and installation and maintenance will cost $1,677,600 and that program administration and marketing will cost approximately $148,000. In 2009 the total costs to Idaho Power are anticipated to be about $6.7 million.

The total expected program costs and estimated total benefits results in a benefit/cost ratio of 1.27 for the first year of the Program. Figure 3 depicts a graph on a per kW basis of the estimated benefits and costs pertaining to the program during 2009.

Figure 3. Irrigation Peak Rewards Dispatchable Option Benefit/Cost Results



In summary, Idaho Power believes the benefit/cost ratio of 1.27 is adequate for the first year of the program based on the number of assumptions that have been applied in this analysis. Although it is expected the program will continue to grow in participation resulting in overall increased costs, higher equipment costs are realized in the first year. Therefore, Idaho Power expects the dispatchable program option will remain cost-effective and viable as a program offering in future years.