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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	CASE NO. PAC-E-10-07
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	Rebuttal Testimony of Carol L. Hunter
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

November 2010

Introduction

Q. Please state your name and business address.

A. My name is Carol L. Hunter. My business address is One Utah Center, 201 South Main, Salt Lake City, UT 84111.

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

A. I am a Vice President for Rocky Mountain Power.

Q. Please describe the responsibilities of your current position.

A. I am responsible for demand-side management for Rocky Mountain Power and for Pacific Power. This includes, the planning, development, design, approval and implementation of programs designed to reduce energy consumption through energy efficiency and behavioral changes and to reduce consumption during peak periods of usage through load control.

Qualifications

Q. Please describe your background.

A. I received a B.S. in mechanical engineer in 1977 and an M.B.A. in 1987 from the University of Utah. I joined PacifiCorp in 1977 as a customer service engineer and have held various management positions in resource planning, wholesale marketing, community and business services and economic development. In 2004, I was promoted to vice president.

I held numerous board positions over my 30 year career and currently serve on the executive board of the Salt Lake Chamber of Commerce, the Idaho Strategic Energy Alliance and the energy efficiency subcommittee of the Utah Energy taskforce.

Q. Have you previously filed testimony in this proceeding?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to or rebut certain issues raised in the testimonies of Mr. Randy Lobb and Mr. Gary Grayson of the Idaho Public Utilities Commission (the "Commission) Staff as it relates to the investment in the company's energy efficiency and load control programs.

Q. Please summarize Mr. Grayson's testimony as it relates to the Company's energy efficiency and load control programs?

A. Mr. Grayson addressed: (1) the prudency of the 2008 and 2009 investment in energy efficiency; (2) the issue he refers to as "customer segment equity"; and (3) the use of a tariff rider to recover the costs associated with the Company's demand-side management programs.

Q. Please summarize Mr. Lobb's testimony as it relates to the Company's irrigation load control program?

A. Mr. Lobb believes that the irrigation load control program allocation is not reasonable because "Idaho receives a reduction of system costs that equate to a program benefit of approximately 66 percent ($7.0 million/$11.4 million) of the costs."[1] He views this as unfair when 100 percent of the program costs are directly assigned to Idaho. Mr. Lobb proposes that the "Company treat the program costs as system purchase power cost and allocate them just as it would any other system power supply expense."[2]

[1] Randy Lobb Direct Testimony Page 15, Lines 3-5.
[2] Ibid, Page 16, Line 2-4.

Prudency

Q. Did Mr. Grayson find the 2008 and 2009 energy efficiency and load management programs operated by Rocky Mountain Power in Idaho prudent.

A. Yes, he indicates that the 2008 – 2009 programs were "generally prudent and cost-effective."[3]

Q. Please summarize Mr. Grayson's testimony regarding "customer segment equity."

A. Utilizing the total investment in energy efficiency and load control for the company's programs in 2009, Mr. Grayson calculates the percentage of the total investment by class. Based on this analysis he determined that 81 percent of the DSM expenditures were associated with the irrigation load control program with the remaining 19 percent going to support the residential energy efficiency programs (6.5%,) commercial/industrial (4.5%,) agricultural (5.9%) and market transformation (2.1%.) Based on this evaluation he indicated that the Company should endeavor to find ways to "pursue all cost-effective DSM while striving toward greater balance with regard to customer segment equity."

It is important to note that while Mr. Grayson's analysis is correct when looking at the overall demand-side management portfolio, the energy efficiency portfolio, excluding market transformation is fairly well balanced between classes; residential at 38 percent of the investment made in energy efficiency, commercial/industrial at 27 percent and agriculture at 35 percent.

[3] Gary Grayson Direct Testimony, page 7 lines 4-9.

Q. What steps can you take to achieve "customer segment equity"?

A. Mr. Grayson did not define customer segment equity. Rather he merely indicated that based on his analysis of the expenditure by customer segment as a percentage of total investment PacifiCorp had not achieved customer segment equity. It appears that he is seeking to achieve an even distribution of funds across the three customer segments; that is 33 percent of the total investment to be made in each of the segments regardless of the type of resource (load control verses energy efficiency). In general I believe there are only four possible approaches to achieving customer segment equity. They are: (1) to expand cost effective program offerings to segments where the expenditures are below average; (2) to suspend or otherwise restrict cost effective programs offered to segments where the expenditures exceed the average; (3) to take actions associated with a combination of (1) and (2); or (4) establish three separate balancing accounts, one for each segment.

Q. Can you achieve customer segment equity by expanding cost effective program offering to segments where the expenditures are below average?

A. As noted in Mr. Grayson's testimony there is relatively little difference between expenditures for residential energy efficiency programs (6.5%) and the commercial/industrial (4.5%) especially in comparison with the difference between the investment in these two segments and the investment in agricultural programs (86.9%). The large disparity is due to the investment in the Idaho irrigation load control program.

We could attempt to accelerate the acquisition of energy efficiency savings in the residential and commercial/industrial segments by increasing incentives. Modest increases might improve the "customer segment equity" without a significant impact to the program cost effectiveness or quality control. Significant increases, however, could reduce the cost effectiveness and have an adverse impact on the quality control of the programs. Consequently while you could mitigate an imbalance in the customer segment equity increasing spending in the other customer segments could raise prudency issues.

As an alternative or in addition to increases in investment in the residential and commercial/industrial segments, steps could be taken at this time to reduce the investment in the agricultural segment in 2011without an adverse impact on the overall cost-effectiveness of the demand-side management portfolio.

Q. How would you approach reducing the investment in the agricultural segment?

A. There are only two programs available to this segment; the Agricultural Energy Savers Program and the irrigation load control program. As Mr. Hedman indicated in his direct testimony both of these programs were cost-effective; however, the Agricultural Energy Savers program's benefit to cost ratio was lower than the irrigation load control program's benefit to cost ratio on a utility cost test basis and the participants cost test basis. While from a utility standpoint the Agricultural Energy Savers program is cost effective, eliminating the program would have a beneficial impact on the overall energy efficiency portfolio cost effectiveness. The overall energy efficiency portfolio cost effectiveness would improve from 1.93 to 2.05 as measured by the utility cost test.

Q. Would you recommend this action absent the issue of customer segment equity?

A. While the 2009 Agricultural Energy Savers program was determined to be cost effective, the program's benefit to cost ratios, as measured by the PacifiCorp total resource cost test, the total resource cost test, utility cost test, and the ratepayer impact test, are lower than irrigation load control's benefit to cost ratios. Consequently before reducing the irrigation load control program beyond the recommendations I discuss later in my testimony, I would recommend eliminating the Agricultural Energy Savers program.

Irrigation Load Control Program

Q. What is the current status of the irrigation load control program?

A. Two of the three third-party delivery vendor agreements utilized in operating this program were set to expire on December 31, 2010. Based on the expiration date of these agreements a request for proposal ("RFP") was prepared and issued in July of this year. The RFP was later cancelled given uncertainty related to the ongoing nature and structure of the program and the potential changes resulting from the Staff's review and recommendations.

At this time we have extended the remaining two agreements through 2011 and anticipate the RFP will be reissued during the second quarter of 2011. The RFP includes an option for the continued operation of the program utilizing multiple vendors as subcontractors. Once the responses are received they will be evaluated on technical and commercial terms prior to awarding an agreement. If the current approach is determined to be less costly after consideration of the technology and risk, the Company will continue operating the program as it does today. Otherwise, the new agreement covering the operation of the program will be completed in time for the 2012 control season.

It is important to note however, any control unit purchase before or during the 2011 control seasons has a reasonable probability of only being in service one year as a result of the procurement process.

Q. What actions must the Company pursue pending re-procurement?

A. As stated, the company will be extending its agreement. To avoid purchasing new equipment the company will seek to optimize the existing equipment. While the company has had the authority under its tariff to restrict participation by customers with irrigation equipment motor load size less than 30 Hp, it has not done so. However when we factor in the cost associated with recursive field costs, which doesn't vary by pump size, the smaller pumps contribute less to the overall cost effectiveness of the program. By restricting participation during the 2011 control period to equipment greater than 30 Hp in size approximately 300 control units will be made available to replace damaged or failed units on larger equipment while only reducing the total connected irrigation load under contract by approximately 8 megawatts. If we extend the limitation to all equipment 50 Hp or less in size approximately 500 control units will be made available with a total reduction of approximately13 megawatts. In summary, by limiting participation in 2011 to larger equipment we optimize the use of the equipment thereby improving cost effectiveness.

Q. How do you respond to Mr. Lobb's concerns that Idaho customers may not be receiving the full benefits of the program while paying for the full cost?

A. This situation may exist if the current costs are built into rates in 2011 on an Idaho situs basis. However, the company is also placed in a difficult position by Staff's proposal that an allocation of costs would occur, shifting program costs away from Idaho to other states before the issue has been addressed and resolved by the MSP Standing Committee or factored into cost recovery filings in other states. While the program is cost effective as compared to alternatives, shareholders do not receive compensation for benefits achieved (costs not incurred), only the recovery of its actual costs. As a result, the company believes that 2011 should be treated as a transitional year to afford the company and Staff the opportunity to work together to address the treatment of Class 1 DSM resources with the MSP Standing Committee.

Additionally, the Company believes that certain changes need to be made to the program to increase its cost effectiveness and resolve operational issues that have been identified during the last two years as the program rapidly expanded.

Q. What changes do you propose?

A. The company proposes that the irrigation load control program continue to be treated as a situs assigned cost during 2011 to allow the issue to be addressed with other states through the MSP process. Additionally, the Company proposes to make certain adjustments to the program to reduce the costs of the program and increase its effectiveness.

Q. Please identify the changes that you are proposing to the irrigation load control program.

A. The Company proposes that the following changes be made to the program:

- Increase the authority under the tariff to restrict participation by customers with irrigation equipment motor load size from less than 30 horsepower (Hp) to a minimum of 50 Hp;
- Add Idaho Power's participation selection language to the tariff

  > "The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to; Billing demand, location, pump horsepower, pumping system configuration, or electric system configuration. Past participation does not ensure selection into the Program in future years. Participation may be limited based upon the availability of the Program equipment and funding."

- Change the penalty for opt-out events available to the Schedule 72A participants to a percentage reduction in the participate credit for each event as follows:
  - 1 opt out event 100% of the participation credit paid to participant
  - 2 opt out events 90% of the participation credit paid to participant
  - 3 opt out events 70% of the participation credit paid to participant
  - 4 opt out events 50% of the participation credit paid to participant
  - 5 opt out events 25% of the participation credit paid to participant
  - 6 opt out events participation in program terminated for the year
- Reduce the participation credit to $25 per kW in 2011 and then reinstitute the $30 per kW in 2012;
- The Company and IPUC Staff should work collaboratively to address the issue of system allocation of demand response programs with other states through the MSP Standing Committee or other appropriate venues.

- The program will be treated as a system resource in 2012, subject to other states agreeing to the allocation treatment.

Q. Do you have any recommendations regarding the operation of other programs?

A. Yes, I would also recommend the NEEA program and the Agricultural Energy Savers program be discontinued in Idaho effective January 1, 2011. The current collection rate of 4.72 percent will continue and the elimination of these two program expenses will allow the Company to reduce the past balance of prudent program expenditures over a shorter amortization period.

Q. Please explain your recommendations to increase the minimum participation level to 50 Hp.

A. We are seeking to increase the minimum level to 50 Hp in an effort to optimize program realization and better utilize the direct load control units currently in use. The chart below demonstrates the negative cost benefit of the smaller pumps:

Pump Size	kW	Benefit @ $44/kW	Cost	Net Benefit
30	22	985	1,340	(355)
35	26	1,149	1,340	(191)
40	30	1,313	1,340	(27)
45	34	1,477	1,340	137
50	37	1641	1,340	301

Q. Please explain the change in tariff language you are recommending to align the company with Idaho Power's participation selection language.

A. Beginning in 2008, the program manager for the irrigation load control program began fielding complaints from the distribution field engineers regarding voltage excursions during dispatch events. In response, the program manager began notifying distribution engineering of pending events so troublemen could make the necessary adjustments to the system to limit the impact to the system. Program participation continued to grow and in 2009 the solution implemented in 2008 was insufficient to address the issue.

During the period following the 2009 control season the program manager working with the company's engineers identified the upper limits of the load that could be removed from each circuit without adversely impacting the distribution circuit, distribution substation, transmission substation and/or generating voltages that impacted end-use loads. On a circuit by circuit basis and ultimately on a grower by grower basis loads were organized so they could be "stair-stepped" on and off in three minute intervals. While this approach resolved part of the issue there was still an issue on select distribution substations where reductions were limited to a certain magnitude. In these instances only solution was to allocate load away from the 2:00 – 6:00 p.m. dispatch to two dispatch periods 11:00 a.m. – 3:00 p.m. and 3:00 – 7:00 p.m. The result was three distinct dispatch periods and within each of the dispatch periods approximately five different "stair step" dispatches. While this best utilizes the loads under management it dilutes the program's contribution during the highest peak hours when the control is need the most.

By including language in the company's tariff, Rocky Mountain Power would have the flexibility to manage the load on any given substation or circuit. By better managing the loads we can improve the impact of the load control program at peak, lower costs and as a result improve cost effectiveness.

Q. **Would the Company be requesting this change absent the concerns expressed by Mr. Lobb and Mr. Grayson?**

A. Yes. As participation in the program has increased, transmission and distribution issues of this nature have become more prevalent.

Q. **Please explain the changes to the opt-out penalties you are recommending.**

A. Let me start by summarizing the current program. Participants in Schedule 72A Dispatchable Irrigation program agree to allow the Company to dispatch their pumps for 52 hours per year. Each dispatch event cannot exceed four hours totaling a maximum of 13 interruptions annually. Program participants are permitted to "opt-out" of up to five events on the sixth event they are terminated from the program. If they do opt-out they pay the posted day ahead market price. While the company only experienced 2.9 percent of customers opting out of control events, the penalty associated with opting out is inconsistent with the impact to the program. Consider the following example:

- Assume an irrigator opts a 135 Hp pump (100kW) out of the program during five control events.
- Assume an average value of the liquidated damages in 2010 currently provided for in the tariff.

- Under the current tariff provision the irrigator would receive 96 percent of the total participation credits.
- Based on the proposed opt-out schedule the irrigator would only retain 25 percent of the credits.

The proposed change will improve the performance of the program by (1) reducing the number of opt-outs and as a result increasing the amount of load reduced during events, and/or (2) reducing the total incentives reducing the overall cost of the program.

Q. **Would the company be requesting this change absent the issues raised in this case?**

A. Yes.

Q. **What would the impact be to the program if the incentive payments are lowered to $25 during 2011?**

A. We anticipate that some customers will elect to suspend participation in the program. Given the number of factors that may impact a customer's decision to suspend participation, we are unable to provide an estimate of the impact on the overall size of the program. Assuming however 230 megawatts of connected load, the proposed change in incentive payments will result in a $1,150,000 reduction in credits.

Q. **How would customers benefit from these program changes if they reduce costs and increase program effectiveness?**

A. The company will credit the savings from these changes to the demand-side management balancing account for the program savings in excess of the amount in base rates and reduce the amount owed from customers to the company in that account. This will speed up the amortization of that account and provide greater flexibility with the level of the surcharge related to the DSM program cost recovery.

Q. Will these changes resolve the customer segment equity issue raised by Mr. Grayson?

A. No. While reducing the costs mitigates the issue raised by Mr. Grayson it does not eliminate the issue. To ensure customers in one class are not paying for energy savings or load control in another class, the costs associated with each segment could be assigned a separate balancing account representing the segments identified by Mr. Grayson. The cost associated with each balancing account would then be recovered from the appropriate customer segment. For example, the cost associated with energy efficiency programs are assigned to three separate balancing accounts in Wyoming – residential, commercial/irrigation and large industrial. The cost associated with each segment is recovered from the customers in the segment. A similar approach could be used in Idaho separating the costs into the three customer segments identified by Mr. Grayson.

Q. You stated that Mr. Grayson questioned the use of a tariff rider for recovery of costs associated with the company's energy efficiency and load control programs. Can you expand?

A. Yes. He indicated that most customers are not familiar with the long-term benefits associated with energy efficiency and load control programs and as a result customers, especially non-participants, question the customer efficiency service charge. Mr. Grayson however did not recommend a solution.

Q. Does the company utilize a line item customer efficiency service charge to recovery costs associated with energy efficiency in all of its jurisdictions?

A. No. Consistent with the other states served by PacifiCorp, the Washington Utilities and Transportation Commission utilizes a balancing account to ensure recovery of all expenses associated with demand-side management. However, rather than setting a rate based on a percent of revenue to recover the costs, the Washington Commission sets a rate based on the cost per unit of sales. The rate is then applied to a customer's usage and incorporated in the overall cost of providing service, eliminating the need for a customer efficiency service charge on the customers' bill.

Q. Would this eliminate the issue raised by Mr. Grayson in his testimony?

A. Yes, as I understand his issue.

Q. Does this conclude your rebuttal testimony?

A. Yes.