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Division of Public Utilities

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Memorandum

TO: Public Service Commission

FROM: Division of Public Utilities
Philip Powlick, Director
Energy Section
Artie Powell, Energy Manager
Jamie Dalton, Utility Analyst
Abdinasir Abdulle, Technical Consultant
Charles Peterson, Technical Consultant

DATE: January 22, 2009

RE: Docket No. 08-035-T10: Advice Filing 08-11, Schedule 96A – Dispatchable Irrigation Load Control Credit Rider Program.

I. ISSUE

On December 17, 2008, pursuant to the requirement of Rule R746-405D, Rocky Mountain Power ("Company") filed an Advice Filing 08-11, Schedule 96A – Dispatchable Irrigation Load Control Credit Rider Program – and economic analysis in support of it. The purpose of this filing is to propose tariff sheets implementing a dispatchable irrigation load control program in Utah. The program will be similar to the existing load control program offered under Schedule 96. The difference between Schedule 96 and proposed Schedule 96A is that under Schedule 96 load curtailment is pre-planned and scheduled. With Schedule 96A, irrigation customers may be interrupted at the Company's discretion. In return for allowing the Company to interrupt service, the Company will pay or credit back to the participants a Load Control Service Credit (LCSC). This program supplements the existing program which will continue as before. On December 18, 2008, the Public Service Commission (Commission) sent an Action Request to the Division of Public Utilities (Division) requesting comments by January 22, 2009.

II. RECOMMENDATION

The Division recommends that the Commission approve the proposed tariff sheets implementing a dispatchable irrigation load control program in Utah, after they have been revised to reflect the corrected line loss figure and the corrected Irrigation Season dates. The Company should also file a corrected benefit-cost analysis that reflects the corrected line loss figure.

III. DISCUSSION:

Program Description:

This optional program is available to customers served on Schedule 10. Customers who choose to participate in the program should execute a Load Control Service Agreement (LCSA). Customers executing the LCSA will continue to be considered program participants unless a customer explicitly withdraws from the program.

This irrigation rider will be in effect during the irrigation season which is defined as May 25 to September 15. During the season the program will operate between 2 p.m. and 8 p.m. Mountain Daylight Time, Monday through Friday. Each customer has to meet certain requirements in order to participate including a minimum sized pump motor (10 Hp), use specified 2-way communication equipment and be able to manage all irrigation pumping requirements, participate in Company training, have internet access, and be willing to pay for communication charges if there are more than 70 communication transactions during any given month.

The LCSC will be paid no later than October 31 following each irrigation season. The LCSC will be calculated based upon participation volumes times a fixed rate. The participation credit schedule for 2009 is as follows:

Program Participation Volumes (MW)	Participation Credit ($/KW-yr)
Less than 36	$23.00
36 to less than 45	$26.00
45 or greater	$28.00

The Company will notify all eligible Schedule 10 customers by February 15 of the LCSC for that year.

The Company will have the right to reduce or interrupt power to a participating customer between 2 p.m. and 8 p.m. Mountain Daylight Time, Monday through Friday, during the irrigation season. The maximum number of hours that can be interrupted during the season for any one customer is 52; also, no more than four hours at a time, or 12 hours per week can be interrupted. The July 4 and July 24 holidays are excluded. Based on the Company's data response to CCS Data Request 1.8, the Company indicated that participants will be provided with a day-ahead notice and second notice the morning of a dispatch event day. A customer may opt-out of five dispatch events, but the cost of each opt-out is deducted from the customer's LCSC.

Analysis:

The Company notes that this program has the support of the Utah DSM Advisory Committee. The Company has also received indications of strong interest among Utah irrigators. Rocky Mountain Power notes that it has been operating a similar dispatchable irrigation program in Idaho, and views the Utah program as a natural extension of the Idaho program. The Company believes that many of the potential participants in Utah are also located near the Idaho border.

To support this application through a benefit-cost analysis, the Company hired The Cadmus Group (formerly Quantec) to perform a benefit-cost analysis. Cadmus determined that the benefit-cost ratios were positive at 1.37 in its revised calculations. Based upon an explanation from Jeff Bumgarner of PacifiCorp, Cadmus' data was based upon the actual operation of a closely similar program in Idaho. The Idaho program was begun as a pilot program in 2007. The Company estimates that there is over 400 MW in Idaho in potential load that could qualify for this program. By contrast, in Utah the Company estimates that there is only about one-quarter of Idaho's potential load at about 107 MW.

Since there is overlap between the Utah and Idaho agricultural communities at the Utah-Idaho border, Rocky Mountain Power determined that a reasonable estimate of the growth of the program in Utah would be a direct comparison with the Idaho experience, adjusted by the relative size of the potential megawatts that could qualify for the Utah program. The Company estimated that 30 MW would be signed up for the program in the first year (2009). The Division believes this estimate is reasonable.

The $59.83 /kW for the program was calculated to be the avoided cost of the program using the Company's GRID model. The Company also estimated a line loss amount of 6.33 percent. The Division deems these assumptions to be reasonable. Based upon these assumptions, the program described on Schedule 96A should have a positive benefit-cost ratio the first year, and a better ratio thereafter as fixed costs are reduced.

In its answer to the Committee of Consumer Services data request 1.3, the company says it believes that customers participating in the current scheduled outage program (Schedule 96) are likely to migrate to the new dispatchable program (Schedule 96A) based on its experience in Idaho. The Company then suggests between the two load curtailment programs (Schedules 96 and 96A) that about 35,000 kW in peak loads could be curtailed. Of the 35,000 kW, 30,000 kW would migrate to Schedule 96A, the dispatchable program. The Division asked the Company what would happen to the viability of the Schedule 96 program if over 85 percent of the current Schedule 96 participants were to migrate to Schedule 96A? The Company explained that there is very little in the way of fixed costs for the Schedule 96 program, therefore it is expected that it will continue to be a positive benefit program going forward.

The Company reported that its initial line loss adjustment was in error and should have been 6.33 percent. Additionally, on page one of the tariff sheets on page 1 in the paragraph “Applicable,” part (b), the Irrigation Season is defined as June 1 to September 15. The Division understands that the correct Irrigation Season for Utah is May 25 to September 15. The Division recommends that the Company file corrected tariff schedules and a revised benefit-cost analysis based upon the correct line loss adjustment, and with the correct irrigation season dates.

Conclusions:

The Division recommends that the Commission approve Schedule 96A with the revisions mentioned above.

CC: Rea Petersen, DPU
Douglas Larson, RMP
Dave Taylor, RMP
Jeff Bumgarner, RMP
Michele Beck, CCS