ORDER NO. 03-408

ENTERED JUL 16 2003

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1093

In the Matter of	)	
	)	
DEMAND RESPONSE PROGRAMS	)	ORDER
	)	
Recommendations for Portland General Electric Company and PacifiCorp.	)	

DISPOSITION: RECOMMENDATIONS APPROVED WITH REPORTING REQUIREMENTS

At the July 1, 2003 public meeting, Staff presented to the Public Utility Commission of Oregon (Commission) a report recommending Demand Response Programs for Portland General Electric Company and PacifiCorp. Staff's recommendations are attached as Appendix A and are incorporated by reference.

ORDER

IT IS ORDERED that Staff's recommendations are approved, with reporting requirements, as outlined in the attached appendices.

Made, entered and effective ___________________________________.

______________________________	______________________________
Roy Hemmingway	**Lee Beyer**
Chairman	Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law

ITEM NO. 4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 1, 2003

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ________________________

DATE: June 26, 2003

TO: John Savage through Lee Sparling

FROM: Lisa Schwartz

SUBJECT: DEMAND RESPONSE PROGRAMS: Recommendations for PGE and PacifiCorp.

STAFF RECOMMENDATION:

The Commission should approve staff's revised recommendations for demand response programs for Portland General Electric (PGE) and PacifiCorp:

1. The utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs. The Commission should add to the issues list for its investigation into least cost planning requirements (UM 1056): How should demand response be explicitly included in least cost planning on par with other options for meeting energy and capacity needs?

2. The utilities should provide to the Commission by Dec. 31, 2003, an assessment that evaluates demand response potential by market segment, identifies barriers to development and recommends actions. The assessment should include an evaluation of voluntary demand response programs tailored to each customer class, including critical-peak and two-part real-time pricing for large customers and direct load control for small customers with and without critical peak pricing.

3. The Commission should open an investigation to identify policies that facilitate the adoption of more advanced meters, communication technology and automated meter reading.

4. Beginning April 2004, PacifiCorp should report to the Commission at the first regular public meeting each quarter progress toward developing new demand response pilots or programs for small and large customers that are cost-effective now or build capability for the future, based on the results of the Company's demand response assessment. Reporting should continue until such pilots or programs are implemented.

Staff notes that PGE has agreed to bring forward by March 31, 2004, for the Commission's consideration tariffs specifying new voluntary pilots or programs for small and large customers with a proposed effective date of May 1, 2004, based on the results of its demand response assessment.

DISCUSSION:

Staff brought before the Commission at the June 3, 2003, Public Meeting its recommendations for demand response programs for PGE and PacifiCorp. (Staff Report attached.) Staff's study on demand response programs for Oregon utilities provided the basis for those recommendations.

Both utilities expressed concern about Staff's proposed timeline for submitting tariffs and implementing new demand response programs. Staff further discussed this issue with the utilities and revised its recommendations to allow more time to assess and develop programs.

PGE agreed with Staff's revised recommendations. The Company also committed to present to the Commission by the end of September the results of its winter 2003 pilot program to test direct load control for residential water and space heating.

Staff could not come to an agreement with PacifiCorp about filing tariffs for new demand response pilots or programs for small and large customers by a date certain. Staff is considering such a recommendation to the Commission as a condition for acknowledgment of the Company's Integrated Resource Plan to ensure the utility increases its demand response capability in Oregon.

PROPOSED COMMISSION MOTION:

The Commission approve Staff's demand response recommendations 1 through 4 for PGE and PacifiCorp.

ITEM NO. 3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 3, 2003

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ________________________

DATE: May 29, 2003

TO: John Savage through Lee Sparling and Jack Breen

FROM: Lisa Schwartz

SUBJECT: DEMAND RESPONSE PROGRAMS: Recommendations for PGE and PacifiCorp.

STAFF RECOMMENDATION:

The Commission should approve staff's recommendations for demand response programs for Portland General Electric (PGE) and PacifiCorp:

1. The utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs. The Commission should add to the issues list for its investigation into least cost planning requirements (UM 1056): How should demand response be explicitly included in least cost planning on par with other options for meeting energy and capacity needs?

2. The utilities should provide to the Commission by Dec. 31, 2003, an assessment of demand response potential by market segment, barriers to development and recommended actions.

3. The utilities should bring forward by Sept. 30, 2003, for the Commission’s consideration at least one voluntary real-time hourly or critical-peak pricing tariff beginning Jan. 1, 2004, for nonresidential customers with a demand of 200 kW or greater.

4. The utilities should bring forward by Sept. 30, 2003, for the Commission's approval a program to expand their direct load control efforts for small customers in Oregon beginning Jan. 1, 2004. The utilities also should consider testing critical-peak pricing for customers that choose utility load control.

5. The Commission should open an investigation to identify policies that facilitate the adoption of more advanced meters, communication technology and automated meter reading.

Staff has one additional recommendation: The Commission should determine whether time-of-use energy rates should be redesigned and meter charges reduced. Per OAR 860-038-0220(3), the Portfolio Advisory Committee will make recommendations to the Commission no later than July 1st on the time-of-use option. The Commission will act on those recommendations at a subsequent public meeting, and Staff defers this recommendation until that time.

The attached report provides the basis for Staff's recommendations.

DISCUSSION:

The Commission set out as one of its 2002 objectives to investigate the role of demand response programs in providing electricity service, evaluate demand response programs that are appropriate for Oregon's investor-owned electric utilities and work with the utilities to put them into effect.

Demand response programs typically provide a payment or price signal to encourage customers to reduce or shift demand for power during system emergencies, energy and capacity shortages, on-peak hours or periods of high market prices. The benefits are improved reliability, reduced costs for delivered energy, and lower and more stable rates for customers.

PGE, PacifiCorp and Idaho Power used a variety of demand response programs during the energy shortages of 2000-01 to maintain system reliability and rein in high-cost power purchases. The programs achieved sizable load reductions by paying customers to reduce electricity use during peak hours or over a month or season.

Today, only demand buyback programs for large customers remain. Other programs now in place that reduce peak demand rely on retail prices that change over time. They include optional time-of-use pricing for residential and small business customers, a market-based daily pricing choice for nonresidential customers, and on- and off-peak pricing for some large customers.

To carry out its assessment of demand response programs, Staff met with industrial and commercial customers, energy service suppliers, aggregators, consultants and a financial services provider. Staff also obtained detailed information from the utilities on their demand response programs and related issues, reviewed demand response studies and surveyed activities in other states.

Staff then prepared a draft report that reviews demand response tools that can help the utilities meet peak electricity needs, documents the results of the demand response programs Oregon utilities have offered and assesses their effectiveness. Based on Staff's findings, the report makes recommendations for future programs to reduce loads when supplies are tight and to help meet ongoing needs for peak capacity — reducing the need for investments in power plants and distribution upgrades and easing congestion on the region's transmission grid.

Staff shared a draft of the report with PGE, PacifiCorp and Idaho Power on April 21st and met with PGE and PacifiCorp representatives in early May. Staff sent out a revised draft for public review on May 8th.

Staff did not direct its recommendations at Idaho Power, and the company did not comment on them. PGE, PacifiCorp and others have raised the following issues:

Competition With Energy Service Suppliers: Both utilities raised the concern that offering a demand response pricing option for large customers may be at cross-purposes with the development of a functioning competitive market. PUC Staff solicited the opinions of energy service suppliers on this issue.

Lorne Whittles of Epcor agrees with the utilities. He said demand response is part of all contracts the company offers. Energy usage above the contracted level (or above a margin over the contracted level) would be charged at the daily non-firm Dow Jones price for a PGE customer, for example, and Epcor's contracts include provisions to pay customers for load curtailments (similar to the utilities' buyback tariffs). Whittles believes demand response is best provided by the market. If the utilities charge demand response participants day-ahead estimates instead of actual real-time prices, other customers will be exposed to cost shifting when actual market prices are lower than the utility estimated. Further, Whittles believes that any additional pricing option for large customers will hamper competition by making it easier for them to stay with their utility. He believes this is a transitional issue, however. Once Oregon develops a robust competitive market, it may be possible for the utilities to offer a demand response pricing option to nonresidential customers without hindering competition.

Jennifer Thome of Strategic Energy said her company also offers products with an hourly or daily pricing component. As long as there's a level playing field between the utilities' real-time or critical-peak pricing options and Strategic Energy's products, the company believes staff's recommendation would not hinder competition in any way. Strategic Energy is confident it could compete against such a tariff.

Bill Chen of Constellation NewEnergy did not comment directly on this issue. However, he asserts that direct access customers should be able to participate in utility demand response programs. He further states that any costs associated with the implementation of demand response programs must be recovered in a fair and uniform manner across cost-of-service and direct access customers.

Staff does not believe an hourly real-time or critical-peak pricing option would hamper competition. In fact, demand response is critical to the healthy functioning of competitive markets, to serve as a check on market power and runaway prices. Energy service suppliers can sell loads their customers curtail into wholesale markets. But no regional transmission organization is expected to develop in the near future that would offer load reduction programs for the suppliers and their customers. Utilities will remain the major players in demand response. Without a dynamic pricing option, all large customers that do not opt out of the cost-of-service rate will remain on flat rates that provide no real-time response to utility system and market conditions. Staff also notes that in areas of the country with healthy competitive markets, utilities offer demand response programs for remaining customers and participate in programs offered by Independent System Operators.

Importantly, Staff distinguishes its recommendation for a real-time hourly or critical-peak pricing tariff from other pricing options the utilities might want to offer. For example, the multi-year pricing option PGE filed last year would not only have competed with multi-year offers from energy service suppliers, but would have provided benefits only for participating customers. A dynamic pricing tariff would benefit all customers by reducing utility costs.

Regarding direct access customers participating in utility demand response programs, Staff believes the issue is whether the utility's remaining customers would benefit. Staff agrees that in the event of a system contingency, the utilities could take whatever measures are necessary to achieve load curtailments from direct access customers — if they have taken all other measures to avoid blackouts, including providing incentives for bundled customers to reduce loads.

<u>Inconsistency With Direct Access Rules</u>: PacifiCorp asserts that the Commission's direct access rules (OAR 860-038) do not authorize voluntary pricing programs for large customers. First, Staff believes that the PUC statutes are broad enough to allow the agency to adopt rates that provide for hourly real-time or critical-peak pricing options.

Moreover, Staff does not believe the direct access rules restrict the utilities from offering an hourly real-time or critical-peak pricing option intended to improve demand response.

Timing: Both utilities expressed concerns about the timeline for approval and implementation of a new pricing option for large customers and a direct load control program for small customers. PGE would like more time to develop supporting data and prepare utility systems. PacifiCorp would as well, if the Commission requires the company to offer these options.

PacifiCorp adds that its updated load forecast demonstrates no need for additional resources in the near term in Oregon. The utility also believes that current end-use appliance trends and system metrics do not appear to support the need for a load control program for small customers.

PGE suggests that it continue to review demand response programs elsewhere, including California’s new programs, evaluate and develop programs for PGE customers, and update PUC Staff regularly on program status. The utility will be prepared to present program plans by Sept. 30, 2003, along with issues regarding costs and cost recovery, and commit to the filing of a specific tariff later. PacifiCorp proposes supply side RFPs into which load reductions can be bid.

Staff believes that a new demand response pricing option for large customers and a direct load control program for small customers should be in place for both utilities by Jan. 1, 2004:

- It will take time to build up participation in new programs to provide sizable peak reductions. The utilities' Integrated Resource Plans (IRPs) call for new capacity resources for Oregon by 2005 (PGE)-2006 (PacifiCorp).

- Oregon loads are winter peaking, and if programs aren't available next winter, we may not achieve the biggest benefits until 2005.

- Expected new peaking resources in the region have not been developed. That increases the risk of high wholesale prices during needle peaks for the portion of capacity requirements that the utilities meet using the short-term market.

- In Staff’s meetings with large customers and energy service suppliers, they stressed the importance of understanding all rate options for the coming year well in advance of the deadline for opting out of the cost of service rate.

– Staff is uncertain whether the current portfolio of demand response programs will achieve sufficient load reduction in the event of future shortages and high prices.

PGE's IRP Supplement assumes it will achieve 60 MW in 10 years through direct load control. The company laid the groundwork last year, requesting the Portfolio Advisory Committee's support for a pilot program. Staff brought the Committee’s recommendation that the Commission consider it to the July 9, 2002, Public Meeting. The Commission approved PGE's pilot program on Oct. 1, 2002, and PGE ran water heating and space heating control tests for about 200 homes last winter. The company estimated the costs of the pilot program and evaluation at $371,000, to be recovered under its SB 1149 deferral account because of the potential applications of automated load control for time-of-use customers. If the program was found to be cost-effective and accepted by customers, PGE planned to offer it to additional customers. PGE's filing indicated an estimated 5,000 households participating by the end of 2004, with an estimated peak reduction of 4.9 MW. Staff believes PGE will have had sufficient time by Sept. 30, 2003, to review the results of its pilot program and design an expanded program based on its experience to begin by 2004.

Staff also notes that PacifiCorp has developed an air-conditioning load control program for a portion of its Utah territory. The program is expected to achieve an estimated 90 MW of peak demand reduction within three years from 90,000 small customers. Air-conditioning use is increasing in Oregon, and summer peaks are following suit. Marginal costs that time of year also are affected by summer peaking in California.

Staff agrees with PacifiCorp that direct load control should be part of the overall analysis in the company's IRP. The IRP has not yet been acknowledged. The Action Plan calls for new capacity resources for Oregon in 2006, but does not include any new demand response programs for Oregon. Dynamic pricing and cost-effective direct load control should be part of that mix of resources. To be effective in 2006, programs must be started now. The utility plans to issue by June 30, 2003, an RFP for Class 1 and Class 2 DSM resources for 10 years, including direct load control. If the company accepts a bid for a direct load control program for its small customers in Oregon, that program can meet staff’s recommendation. If not, the utility should design its own program.

Regarding pricing programs for large customers, Staff described in its report some of the successful models that utilities can adapt for Oregon. The utilities also can benefit from work recently done in California for programs that begin this summer. Staff notes PGE's comments regarding implementation timeframes in its IRP Supplement: "We have demonstrated that such [voluntary pricing] programs can be implemented within relative short timeframes and with positive results."

Cost Recovery for Large Customer Pricing Program: PacifiCorp asserts that program costs would have to be recovered through a separate surcharge for customers over 200 kW — those eligible for the program. Staff points out that the program would not be offered as part of SB 1149 implementation and that program costs could be recoverable through base rates, not necessarily through a separate adjustment schedule. Further, the benefits of demand response accrue to all customers in the form of reduced utility costs, so some broader allocation of costs within the customer class would not be inappropriate. Staff also notes that the required meters for a demand response pricing program already are in place for customers with a demand of 200 kW or greater.

Meters and Meter Reading Services: Bill Chen of Constellation NewEnergy suggests that the Commission study whether meter-related products and services should be open to competition. He believes that would help energy service suppliers compete fairly with the utilities to offer customers innovative technology and related products to increase the benefits they receive from participating in demand response programs. This topic could be included in the issues list for Staff's proposed investigation into advanced meters, communication technology and automated meter reading.

Discriminatory Pricing: Staff suggests in its demand response report that the utilities consider two-part real-time pricing to meet its recommendation for a dynamic pricing option for large customers. Under such a rate design, customers pay standard-tariff fixed rates for baseline energy consumption, determined by their historical usage, and real-time hourly prices only for deviations.

PacifiCorp raised the issue of whether such a rate design would be discriminatory because a participant and nonparticipant with the same usage would pay different rates, based on historical consumption. (The participant reduced load during peak hours, so its load pattern now matches the nonparticipant's usage.) Staff's recommendation, however, does not prescribe the type of program the utilities submit for the Commission's approval. If a utility is interested in proposing a two-part real-time pricing tariff, Staff's legal counsel can review the issue at that time. Staff notes that participants would have lower rates than cost-of-service customers with the same usage only if they reduce loads during high-priced peak hours by cutting or shifting production, investing in technology and undertaking other load-shifting efforts. It could be argued that participants and nonparticipants are not similarly situated, and therefore price discrimination is not an issue.

Longer-term Buybacks: Staff noted in its demand response report that longer-term buybacks in 2001 appear to have increased utility costs, although we do not know to what extent they reduced market prices and therefore provided ratepayer benefits. The report also illustrates that interruptible rates don’t always achieve the load curtailments expected.

PGE is concerned that Staff's conclusions might preclude the utility from offering in the future a term buyback contract or interruptible rate. Nothing in Staff's recommendations precludes the utilities from signing term agreements under their current buyback tariffs or submitting interruptible rates for the Commission's approval.

Staff recommends the utilities offer an additional pricing option for large customers that more closely matches actual market prices in real-time, offer direct load control for small customers and consider a critical-peak pricing test. Pricing options have lower risks for ratepayers over fixed payment options: No payments are required because the incentives are embedded in prices, and incentives based on more timely information are more likely to match actual market prices. Pricing options (and direct load control) also have the advantage of reducing ongoing capacity requirements through reduced demand forecasts. And some options offer customers a lower rate for using energy during off-peak hours, which also makes better use of generating, distribution and transmission facilities.

Comments of Other Parties: Nathan Carpenter of Boise Paper points out that utilities have an incentive to build generating and delivery facilities over building participation in demand response. Carpenter also believes that the utilities should give demand response participants a greater share of the utility system savings. He asserts that large customers got too small a portion of the savings from their load curtailment efforts in 2000-01, to the point that it often didn't make sense to participate given the business risks of reduced production. Staff also heard these concerns from other large customers we met with. Staff notes that under the current demand buyback tariffs, the utilities have the flexibility to quote prices reflecting any portion of the savings they think is necessary to achieve sufficient load response. With FERC's price cap in the Western market, the utilities likely would need to increase the customer's share of savings to achieve much load response under these programs.

Carpenter suggests that large industrial customers be able to negotiate terms and conditions by which they will trim load given their unique set of operating circumstances. Staff notes that such special contracts are not allowed under SB 1149. Demand bidding, where the customer proposes a bid to curtail energy use instead of the utility setting the price, is an approach the utilities could consider. Staff makes no recommendation for changes to the demand buyback programs at this time.

Marc Steele of Norpac suggests that programs should provide on- and off-peak prices, rather than hourly prices, because meeting load reduction goals every hour would require a sophisticated in-plant energy control system. Under Staff's recommendation, the utilities could offer a rate structure with on-, off- and critical-peak pricing periods. Among other real-time options, they also could offer a pricing design where customers pay real-time hourly prices only for deviations from baseline usage. Either of these options would reduce, but not necessarily eliminate, the need for additional control systems. Steele also suggests that the utilities provide sufficient warning to customers before using their buyback programs again, so they can get ready to respond.

Lynn Frank of Utility Systems & Applications, an energy services company, suggests the utilities conduct an assessment of demand response potential by market sector. Staff agrees and makes that recommendation. Frank stresses that the utilities also should help customers get the technical assistance and technology they need to achieve their full cost-effective potential for load reduction. He points out that economies of scale and additional applications of demand response technologies can increase their cost-effectiveness. These issues can be considered in Staff's recommended investigation into policies on metering and related technologies. He also cites other barriers that need to be addressed, including codes and licensing issues.

Ken Corum of the Northwest Power Planning Council believes the evaluation and recommendations in Staff's demand response report summed up well demand response experience in the region. He submitted new Council analysis showing conservative values for the Northwest in the range of $200 to $1,000 per MWh for the avoided costs of building peak capacity resources.

The Demand Response and Advanced Metering Coalition commended Staff for avoiding a focus only on demand response for large customers. The Coalition is an advocacy organization comprised of utilities, metering and communications companies and public interest groups that promotes policies to foster demand response, particularly dynamic pricing for small customers. The group says Staff's report correctly points out that all customer classes respond to price signals for electricity in ways that benefit them and the electricity system, that critical-peak pricing offers great potential, that advanced meters installed by the utilities should allow flexibility for a variety of dynamic pricing designs, and that automated meter reading and economies of scale should be considered in determining metering policies.

The Coalition supports Staff's recommendations, with the following comments: First, the experience, case history and enabling technology now exist to allow the utilities to include demand response, including dynamic pricing, as a long-term resource that can reliably and effectively shape load and load forecasts used in IRPs. Second, the Commission should move forward to implement critical-peak pricing programs. Third, rate design and allocation of costs for meters and other enabling technology are important considerations. Further, decisions about advanced meters should not be made in isolation from automated meter reading and demand response programs — and their benefits for utilities and customers. Finally, the Coalition asks the Commission to adopt an expedited timeframe for Staff's proposed investigation into policies on metering and communication technology.

David Zerba of FirstPoint Energy, an energy services company, believes very little sustained savings has resulted in the Pacific Northwest for the amount of money spent on demand response. He suggests the utilities implement his company's Customer Demand-side Advantage Savings program for sustained peak energy management. The program is directed at commercial and residential customers. It consists of interval metering, Internet access for customers to energy usage data and savings, and a credit on monthly utility bills for reductions in peak demand.

Phil Carver of the Oregon Department of Energy supports Staff's recommendations, in particular that additional demand response actions are needed now for two reasons: to prepare for potential capacity problems in the Western interconnection and to foster competition in wholesale markets. Carver states that if Western loads grow as projected, there may be serious summer and winter capacity problems in a few years, and it can take years for demand response programs to build sufficient customer participation to be effective. Carver also cites the importance of demand response for ensuring the utilities can continue to rely on wholesale markets for part of their peak demand. Otherwise, the West will have excessive reserve margins. Because of diversity in the loads and resources in the West, utilities can minimize costs by relying on each other for peak resources through wholesale power markets. In order to do so, markets must be reasonably competitive. Carver believes that is unlikely without an effective demand response to high wholesale prices.

PROPOSED COMMISSION MOTION:

The Commission approve staff's demand response recommendations 1 through 5 for PGE and PacifiCorp.

DemandResponsePMM6-3-03.doc