Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option

Portland General Electric

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Executive Summary

Introduction

On March 28, 2004 Portland General Electric (PGE) filed with the Oregon Public Utility Commission (OPUC) its initial report of the Time of Use (TOU) rate plan, called "Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option". Since that time, PGE refined the demand side program measurement and evaluation model. The TOU data was rerun through the new spreadsheet model and the results are reported here in the revised report.

There are three changes incorporated in the evaluation. The fundamental change in the methodology is a close adherence to the California Standard Practice Manual for measuring the Total Resource Cost (TRC) of demand side programs. PGE also revised its capacity values to reflect current market indicators for generating capacity, and also included in one of the revised analyses a value for avoided transmission and distribution (T&D) costs in order to test cost/benefit sensitivities. Another major change was measuring the effectiveness of the program on a going forward basis that excluded sunk costs associated with startup.

The original analysis reported that the TRC benefit/cost ratio (B/C) was 0.32 for "base case", a case which included program development, implementation, and operating costs; and a B/C of 0.53 for demand impacts during the top 87 critical peak hours during the measurement year. A B/C of 1.0 is considered the breakeven cost effective point.

Under the revised calculations for a program moving forward, after sunk costs of development are excluded, the critical peak TRC is 0.58. Due to the limited enrollment in the TOU rate plan, there is likely to be little effect on reducing transmission and distribution costs; therefore, they were excluded from the calculation. Including T&D costs is consistent with the practice of the Northwest Power and Conservation Council. If the benefit of reduced transmission and distribution costs are included, the B/C for a program going forward is 0.74.

A factor for free ridership was not included in either calculation.

Summary

In November 2001, PGE filed a residential TOU rate schedule with the OPUC in compliance with the requirements of OAR 860-038-0220 and pursuant to the recommendations of the State Portfolio Advisory Committee (PAC).

In December 2003, PGE engaged the services of Quantec, LLC, a Portland-based energy consultancy to evaluate the load impacts of the TOU rate option.

The analytic method of this assessment relied on a "quasi-experimental" research design, involving a comparison of load and consumption patterns between participants in the TOU rate and a sample of customers from PGE's residential load research group.

The main findings of this evaluation are:

- The largest impacts of TOU rates tend to occur during the winter morning peak hours. TOU customer loads were, on average, 0.27 kW (15%) and 0.13 kW (7%) lower than that of the control group during the winter morning and evening peak periods respectively. Load impacts during the summer peak period tend to be much smaller in magnitude, averaging 0.03 kW, or approximately 2% of the average load during the peak period.
- The highest average reduction in any one-hour time slot for daily winter peak periods was 0.32 kW (17%), occurring between 8:00 a.m. – 9:00 a.m. The maximum observed hourly reduction during the critical system peak period, i.e. the highest one percentile (87 hours) region of the system load duration curve, was 0.64 kW, or 27% of the average load, which occurred between the hours of 8:00 and 9:00 a.m. in winter. The average peak reduction in the top one percentile was 0.52 kW, which was used in the B/C analysis.
- Participation in the TOU rate option also resulted in an average net reduction of 292 kWh/year in annual consumption. Average monthly usage for TOU participants is just over 1,000 kWh.
- PGE applied the B/C model mentioned in the Introduction to this section for measuring the economic performance of the program in critical peak hours under two scenarios: a development and implementation scenario, and a "going forward" scenario. The results of this analysis, as shown in Table ES.1, suggest that the expenses of the program are unlikely to be offset by its benefits from a total resource cost perspective in either scenario. The program can be expected to yield a 0.58 B/C ratio under the development and implementation scenario and can be expected to yield a 0.74 B/C ratio under the "going forward" scenario for critical peak hours. The

B/C ratio for the program going forward without the benefit of reducing transmission and distribution costs is 0.58.

The B/C ratios are not discounted for free riders, that is, those who made no changes. The estimated number of free riders is between 20%- 45% of total participants.

- On average, annual electricity bills for TOU participants were $28 lower (5%, or $2.37/month) than they would have been under the standard residential rate schedule.

Table ES.1: Summary of Load Impacts and Economic Outcomes Under the Development & Implementation and Critical Peak Scenarios

	Mean Load Impacts	Benefit/ Cost Ratio
Time Periods		
Winter a.m.	0.27 kW	
Winter p.m.	0.13 kW	
Summer	0.03 kW	
Maximum Critical Peak Hour		
Winter a.m.	0.64 kW	
Average Critical Peak Hour winter demand	0.52 kW	
Development & Implementation Scenario		0.58
Going Forward Scenario w/T&D reduction		0.74
Going Forward w/o T&D reduction		0.58
Conservation	292 kWh/Year	

Customer interest in the TOU rate option has been low. However, surveys of TOU participants conducted by PGE have shown that nearly two-thirds (66%) of participants were very satisfied with the rate option and their expectations from the program were fully met