Resource Insight, Inc.

Peak-Shaving/Demand Response Analysis

Load-Shifting by Residential Customers

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1. Introduction

Restructuring of New England's wholesale and retail electricity markets has renewed interest in managing or shaping customer demand patterns. Recognizing the potential for price-responsive load to dampen wholesale-price volatility and to mitigate generator market power, the Federal Energy Regulatory Commission included demand response as a key component of its recently proposed Standard Market Design for wholesale electricity markets. At the wholesale level, ISO-New England and other Independent System Operators throughout the Northeast have established pilot and full-scale programs that allow market participants to submit bid prices for reductions to customer load as they would for dispatch of generation.

At the retail level, market participants are exploring a variety of program designs for shifting customer usage from high-priced on-peak hours to lower-priced off-peak hours, n order to dampen the impact of price spikes and generally reduce the cost of procuring power supply from competitive markets. For larger commercial and industrial facilities with hourly metering, "demand-response" or "peak-shaving" programs typically involve customer curtailment of load at specific times of the day, either by request of that customer's retail power supplier or in response to real-time price signals. For smaller commercial and residential customers, such programs provide either for remote control and interruption of customers' air-conditioning equipment by retail providers or customer-initiated shifting in response to differences in monthly rates for on- and off-peak usage.[1]

This resource assessment focuses on estimating the potential for load shifting by residential customers in response to a time-of-use (TOU) rate design with differential pricing for on- and off-peak usage.[2] Our analysis estimates the average customer response in terms of shifting usage from peak to off-peak periods. It evaluates differences in on- and off-peak rates in a representative TOU rate design. In addition, the resource assessment projects the likely savings in power-supply

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[1]Recent program designs have combined these two approaches, using sophisticated controllers with two-way communications capability that allow both direct control of air-conditioning equipment by the retail provider and customer programming of thermostat settings that trigger in response to real-time price signals provided through the controller.

[2]Given current trends of increasing penetration of central air-conditioning in new construction, direct control of air-conditioning equipment may eventually prove to be a viable demand-response resource for the Cape and Vineyard.

costs and T&D investments during the forecast horizon as a result of customer participation in a TOU pricing program.[3]

The analysis of residential peak-shaving potential involved the following analytical tasks:

1. Estimate the average price difference between on- and off-peak rates for a representative TOU rate design.
2. Based on the results of previous studies of TOU impacts, estimate the elasticity of substitution between on- and off-peak usage, i.e., the amount of shifting per unit difference in on- and off-peak prices.
3. Estimate the amount of shifting per customer given the differential in on- and off-peak prices in our representative TOU rate design and the estimate of substitution elasticity.
4. Project the aggregate amount of load shifting for the residential class based on the estimate of per-customer shifting and an assumed program participation rate.
5. Estimate the impact on power-supply costs for customers under TOU rates, and the reduction in system-wide T&D costs.

2. Time-of-Use Rate Design

We developed a representative rate design based on hourly wholesale-market energy prices and hourly residential-class load data. For hourly energy prices, we used clearing prices for ISO New England's day-ahead energy market for the year 2002. For hourly loads, we used 1995 Commonwealth Electric hourly load data for the R1 and R3 residential rate classes.

We defined the rating periods for the peak and off-peak rates according to the current Commonwealth optional TOU distribution tariff 'Rate 39'. The on-peak period is defined differently for Daylight Savings Time (DST) and Eastern Standard Time (EST). The DST peak period is defined as 9 a.m. to 6 p.m. on non-holiday weekdays, while the EST peak period is defined as 4 p.m. to 9 p.m. on non-holiday weekdays. There were six holiday weekdays excluded from peak

[3]This resource assessment does not include an evaluation of the cost-effectiveness of a residential TOU program. Estimating the capital, installation, and maintenance costs for TOU meters, as well as program administration costs, were beyond the scope of this assessment. Program economics will also depend on the extent to which load shifting by participants reduces generation market prices for non-participants.

period analysis. The 2002 DST period began on April 7th at 2 a.m. and ended on October 27th at 2 a.m. The remaining 2002 calendar days fall into the EST period.

Using these rating-period definitions, we calculated the average of hourly wholesale energy prices–as weighted by hourly loads–in each rating period for each month for 2002. We then calculated the ratio of on-peak to off-peak weighted-average prices in each month, as well as for the year and for the summer and winter seasons. These ratios are provided in Table 1 below.

Table 1: R1 and R3 Residential Class On-Peak to Off-Peak Price Ratios (Pp/Po)

	R1 Load Class On-Peak to Off Peak Ratio	R3 Load Class On-Peak to Off Peak Ratio
January	1.40	1.46
February	1.40	1.44
March	1.32	1.37
April	1.46	1.52
May	1.55	1.60
June	1.65	1.68
July	1.93	1.92
August	2.13	2.12
September	1.39	1.42
October	1.23	1.26
November	1.36	1.41
December	1.33	1.37
Summer	1.78	1.78
Winter	1.38	1.43

Based on these ratios, we adopted values of 1.78 and 1.40 for summer and winter peak to off-peak price ratios, respectfully, for the residential class as a whole.

3. Estimate of Substitution Elasticity

In order to determine the likely customer response to a TOU rate structure, we reviewed a number of studies of residential TOU programs published over the past 30 years. These studies typically utilize the elasticity of substitution as a measure of the consumer substitution responses to relative price changes. The formula for the substitution of elasticity is as follows:

(1) $\ln(Kp/Ko) = \alpha - \beta * \ln(Pp/Po) + \varepsilon$

(2) $\alpha = \ln[Wp/(1-Wp)]$

Where

Kp denotes usage during the TOU on-peak pricing period

Ko denotes usage during the TOU off-peak pricing period

Pp denotes the price of on-peak energy usage

Po denotes the price of off-peak energy usage

β represents the elasticity of substitution between on-peak and off-peak electricity usage

Wp denotes the share of usage consumed during the on-peak pricing period under standard rates

ε denotes stochastic variation in consumer preferences

The substitution elasticity thus represents the percentage change in the ratio of usage between two time periods that occurs in response to a given change in the ratio of prices for electricity during those same periods. An elasticity of greater than zero signifies that consumers reduce their ratio of on-peak to off-peak usage as the peak to off-peak price ratio becomes larger.

The results of the surveyed studies are illustrated in Table 2 below. As indicated in Table 2, the highest reported substitution elasticity was 0.37 for the voluntary PG&E TOU rate experiment.[4] The least responsive experiments were of the mandatory form, as evidenced by the 0.12–0.15 elasticity. Using a peak to off-peak price ratio of 2.5:1, the PG&E elasticity estimate shown in Table 2 of 0.37 implies that on-peak consumption, as a share of total usage, could be reduced almost 5% if consumers voluntarily switched from a flat to a TOU rate structure. If the same assumptions were considered for similar consumers under mandatory TOU rates with an elasticity of 0.15, the on-peak usage would reduce only about 2.0%.

Characteristics of the rate experiments are quite varied. Peak period duration definitions, the number of varied pricing periods per day, peak to off-peak ratios under standard rates, and metering equipment are some of the characteristics that vary significantly between experiments. The GPU experiment was unique in that it utilized an innovative interactive communication system that enabled real-time critical pricing and also allowed customers to pre-schedule their response to

[4]The substitution elasticity for the Puget Sound program is not a reported result; we estimated this value based on information gleaned from a variety of published sources. Although this program resulted in the highest apparent elasticity of all the surveyed programs, it was ultimately found to be uneconomic and was terminated by Puget Sound.

standard TOU prices and critical price. The pre-scheduling was implemented by indicating thermostat settings and circuit interruption at different price levels.

There were three key results of the surveyed experiments. First, as indicated by the results in Table 2, the experiments with voluntary participation had the greatest customer response. Second, usage patterns and responses to TOU rates depended heavily on weather and appliance holdings. The Midwest Power System average consumer response was significantly greater for homes using electric heating. The substitution elasticity for customers using electric heat was measured at 0.39, while non-heating customers exhibited a 0.15 elasticity of substitution. Third, although voluntary participation yielded larger response, this effect was apparently not the result of self-selection by consumers with more favorable usage characteristics. Instead, analyses of the voluntary experiments indicated that volunteers had peak usage shares under flat rates that were similar to the overall residential population.

Based on the survey of studies, we adopted an annual value for elasticity of substitution of 0.3 for the purposes of this assessment of peak-shaving potential. Since the surveyed studies typically did not provide elasticity results separately for summer and winter seasons, we used the annual value to derive seasonal load shifting. By doing so, we may have understated the magnitude of load shifting in the summer period, and overstated likely load shifting in the winter period.

Table 2: Residential Time-of-Use-Rate-Experiment Results[5]

State	Utility	Price Ratio	Elasticity	Voluntary or Mandatory	Experiment Year	Source
Five	5 Utilities	6.2:1 to 16:1	0.12	mandatory	1977–80	Caves ('84)
CA	PG&E	1.9:1 to 2.5:1	0.37	voluntary	1983–84	Caves ('89)
NJ	GPU	2.8:1 to 7.7:1	0.30	voluntary	1997	Braithwait ('00)
OK	Edmon Municipal	4.16:1	0.12	mandatory	1977–78	Huettner ('82)
WI	WPS	2:1 to 8:1	0.15	mandatory	1977	Park ('84)
IA	MPS	4.6:1	0.15-0.39	voluntary	1990–92	Baladi ('98)
WA	Puget Sound	1.18:1	0.53	voluntary	2001	Brattle Group ('01)

4. Per-Participant Load Shifting

The first step in determining per-participant load shifting is computing the ratio of on-peak to off-peak energy usage under existing flat rate schedules. Based on the hourly load data for the R1 rate class, we find that the average customer consumes 27.5% of annual energy usage during the on-peak period (as defined above). Summer usage is approximately 30.2% of total consumption, while the non-summer usage is 25.9%. Residential class R3 exhibited similar peak usage ratios under the flat Commonwealth energy rate schedule. The pre-TOU R1 and R3 class peak usage data is summarized in Table 3 below. Based on 2001 Cape Light Compact Sales (kWh) data for the R1 and R3 classes, we weighted the peak usage

[5]Caves, D. W., J. A. Herriges, and K. A. Kuester, 1989. "Load Shifting Under Voluntary Residential Time-of-Use Rates", The Energy Journal V10, Number 4, 83–99.

Parks, Richard W. and David Weitzel. 1984. "Measuring the Consumer Welfare Effects of Time-Differentiated Electricity Prices." Journal of Econometrics 26, 35–64.

Caves, Douglas W., Laurits R. Christensen and Joseph A. Herriges. 1984. "Consistentcy of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." Journal of Econometrics 26, 179-203.

Braithwait, Steven. 2000. "Residential TOU Price Response in the Presence of Interactive Communication Equipment". Chapter 22.

Huettner, David, Jack Kasulis, and Neil Dikeman. 1982. "Costs and Benefits of Residential Time-of-Use Metering", The Energy Journal V3, No. 3, 99–112.

The Brattle Group. 2001. "An Evaluation of the Impacts of Puget Sound Energy's Time-of-Day Program", November.

Baladi, S. Mostafa, Joseph A. Herriges, Thomas J. Sweeney. 1998 "Residential response to voluntary time-of-use electricity rates", Resource and Energy Economics V20, 225–244.

to arrive at summer and winter usage ratios to represent the residential class as a whole. The weighted on-peak usage ratios are also illustrated in Table 3.

Table 3: Pre-TOU Average On-Peak Usage

	R1 Wp	R3 Wp	CLC Sales Weighted Residential Usage %
Annual Average	27.5%	26.8%	27.4%
Summer	30.2%	30.4%	30.2%
Winter	25.9%	25.1%	25.7%

Note: Wp (on-peak usage under flat rates)

Using the derived average usage under flat rates, seasonal peak-to-off peak price ratios, and elasticity of 0.30, we estimated average per-participant response using the formula shown above. The residential TOU program participant is estimated to shift 3.52% of on-peak usage to off-peak in the summer period (June to September) and 1.88% during the non-summer period (October to May.) Table 4 summarizes the average participant load shifting for the residential class as a whole.

Table 4: On-Peak Usage Shift Induced by TOU Rate Structure

	Residential Class Average Peak Load Shift
Summer	3.52%
Winter	1.88%

5. Aggregate Load Shifting for Residential Class

The aggregate load shift of the Cape's regional demand from peak usage to off-peak usage is dependent on the overall participation level in the TOU rate program. Review of literature on program participation resulted in sparse participation level data for the various TOU designs. Based on the available data, we assumed a base 2010 participation level of 10%, 5% for the low estimate, and 15% for our high estimate. Table 5 below summarizes the TOU program participation found in the literature survey.

Table 5: TOU Program Participation Levels

	Gulf Power (FL)	Midwest Power Systems IA)
Now	0.8%	4.0%
Future	11.0%	5.0%

In addition to Table 5 participation data, a national EPRI choice study found that under the most favorable conditions that about 20% of residential customers would ‘opt-in’ to a TOU program.[6] The most favorable conditions assume customers are completely informed and encounter zero inertia and zero transaction costs to participate in the TOU program. If customers are not informed and there are costs to transact, then the participation level is expected to be about 5%.

Our base, low, and high-case estimates of program participation for 2005, 2010, and 2015 are summarized in Table 6. The estimated 2005 participation levels were inflated to 2010 participation levels and then leveled off.

Table 6: Time-of-Use-Program Participation Assumptions

	Base	Low	High
2005	5.0%	1.0%	10.0%
2010	10.0%	5.0%	15.0%
2015	10.0%	5.0%	15.0%

Table 7 compares the base, low and high-case aggregate load shift estimates for the summer and non-summer periods. These figures are based on a sales forecast where the customer demand annual growth rate equals 3% per year from 2002-2005 and 2% per year from 2006-2015. On an annual basis, approximately two-thirds of all peak consumption took place during the winter months according to Commonwealth’s defined TOU peak period.

Table 7: Aggregate Energy Shifting for Summer and Winter Seasons (MWh)

	2005	2010	2015
Summer			
Base	207	467	525
Low	41	233	262
High	414	700	787
Winter			
Base	181	408	459
Low	36	204	229
High	362	613	688

Table 8 compares the base, low and high-case estimates of aggregate reductions to system peak load for the summer and non-summer periods. These figures are based on the same demand forecast used to generate the energy load shift. The aggregate peak-load for the residential class is assumed to escalate 3% per year from 2002-2005 and 2% per year from 2006-2015. We estimated the reduction to

[6] www.nyserda.org/tsp/Panel3-LisaWood.pdf

peak load from TOU rates by assuming that the percentage reduction to peak load is equal to the percentage shift in energy usage from on-peak to off-peak usage.

Table 8: Aggregate Peak-Load Reduction for Summer and Winter Seasons (KW)

	Base	Low	High
Summer			
2005	506	101	1,012
2010	1,128	564	1,692
2015	1,246	623	1,869
Winter			
2005	270	54	541
2010	603	301	904
2015	665	333	998

6. Time-of-Use-Program Benefits

By shifting usage from peak to off-peak periods, TOU program participants reduce their power-supply costs in two ways. First, they reduce their energy costs by shifting usage from the high-priced peak period to the lower-cost off-peak period. Second, they reduce their cost of procuring reserve capacity associated with their total energy usage by reducing usage during the hour of system peak. Since each customer's reserve-capacity obligation is determined on the basis of contribution to system peak, and since program participation shifts usage off of the hours of system peak, load-shifting reduces capacity obligation and thus the cost of procuring capacity to meet that obligation.

In order to estimate the energy and capacity benefits to program participants, we used the same forecast of Statewide avoided costs used to screen energy-efficiency measures for the Compact's efficiency programs. These avoided costs are provided in Table 9.

Table 9: Statewide Avoided Costs

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Summer Gener. Capacity	Winter Gener. Capacity	Transm. Capacity	Distrib. Capacity
	$/kWh	$/kWh	$/kWh	$/kWh	$/kW	$/kW	$/kW	$/kW
2005	0.0538	0.0419	0.0670	0.0347	26.33	19.39	25.70	152.66
2010	0.0666	0.0427	0.0733	0.0350	39.50	29.10	25.70	152.66
2015	0.0688	0.0447	0.0730	0.0360	39.50	29.10	25.70	152.66

The average residential customer in the Cape Light Compact territory consumes about 500 kWh per month. During the summer, assuming that on-peak usage is about 30% of total consumption under flat rates (as shown in Table 3) and that there is a 3.5% shift from peak to off-peak usage under TOU rates (as shown in Table 4), the average residential TOU participant would realize power supply savings of 17¢ per month. During the winter, assuming that on-peak usage is about 26% of total consumption under flat rates (as shown in Table 3) and that there is a 1.9% shift from peak to off-peak usage under TOU rates (as shown in Table 4), average power-supply savings would amount to only 2¢ per month. The participant bill savings are valued using the avoided energy and generating capacity costs shown in Table 9.

Table 10 provides aggregate power-supply benefits on a program-wide basis, based on the aggregate levels of shifting in usage from on-peak to off-peak periods and of reductions in peak load, as provided Tables 7 and 8, respectively.

Table 10: Aggregate Power-Supply Savings

	2005	2010	2015
Summer			
Base	$ 17,110	$ 52,838	$ 58,407
Low	$ 3,418	$ 26,419	$ 29,203
High	$ 34,220	$ 79,256	$ 87,609
Winter			
Base	$ 10,176	$ 36,075	$ 41,800
Low	$ 2,036	$ 18,014	$ 20,923
High	$ 20,381	$ 53,999	$ 62,723
Annual			
Base	$ 27,286	$ 88,913	$ 100,207
Low	$ 5,454	$ 44,433	$ 50,126
High	$ 54,601	$ 133,255	$ 150,332

Reductions in system-peak load in response to TOU rates will also provide benefits in the form of avoided investments in system-wide T&D capacity. Our projections of program-wide T&D savings are provided in Table 11, and are based on the projections of aggregate peak-load reductions in Table 8 and the avoided T&D costs provided in Table 9. For the purposes of this calculation, we valued reductions in peak load due to shifts in usage at 100% of avoided transmission costs and at two-thirds of avoided distribution costs. We discounted avoided distribution benefits, since (1) certain local distribution equipment will be sized to meet customer maximum demand regardless of when that maximum occurs; and (2) the TOU-related reductions to system peak are simply shifted to off-peak hours, and thus do not reduce customer maximum demand.

Table 11: Aggregate T&D Benefits

	2005	2010	2015
Summer			
Base	$ 21,499	$ 47,927	$ 52,940
Low	$ 4,291	$ 23,963	$ 26,470
High	$ 42,998	$ 71,890	$ 79,410
Winter			
Base	$ 22,943	$ 51,240	$ 56,509
Low	$ 4,588	$ 25,577	$ 28,297
High	$ 45,972	$ 76,819	$ 84,807
Annual			
Base	$ 44,442	$ 99,167	$ 109,449
Low	$ 8,879	$ 49,540	$ 54,767
High	$ 88,970	$ 148,709	$ 164,217

7. Conclusions

In terms of setting priorities for program development over the next five years, it appears from our analysis of customer response to TOU rates that a residential TOU program is not a beneficial investment of resources for the Compact at this time.

- The program benefits are anticipated to be modest. Given current differentials in on- and off-peak wholesale-power prices, our analysis indicates that residential customers on average will shift only 2.44% of on-peak usage to off-peak periods in response to TOU rates. As a result, by 2015 under base-case assumptions, we expect that aggregate savings in power-supply costs for program participants to amount to about $100 thousand per year and that aggregate reductions in system-wide T&D spending to amount to $109 thousand per year.

- We believe the Compact can achieve better returns on its limited funds by focusing on its current energy efficiency programs. We have not estimated the costs to implement and administer a TOU program, so we cannot definitively determine whether a TOU program would be cost-effective from either a societal or participant perspective. However, given the modest levels of load-shifting estimated in this resource assessment, we think it likely that the benefit "return" on investment in a peak-shaving program will be substantially less than the expected 2:1 return on the Compact's investment in energy-efficiency resources.

The Compact should re-assess the viability of a TOU program in the event that developments in the wholesale power markets (such as implementation of Standard Market Design) widen the spread between on- and off-peak prices. In addition, as the penetration of central air-conditioning increases, the Compact may want to evaluate the effectiveness and economics of a residential load-control program, perhaps as an add-on to existing efficiency programs targeted to high-use customers or new construction.