Portland General Electric Company
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May 1, 2007

Email / US Mail

OPUC Filing Center
Vikie Bailey-Goggins
550 Capitol Street, N.E., Ste 215
Salem, OR 97301-2551

RE: **UE 189, Request to Add Schedule 111, Advanced Metering Infrastructure (AMI)**

Portland General Electric (PGE) hereby submits the attached informational document, "Proposed Critical Peak Pricing Tariff." PGE committed to provide this summary document by May 1st as outlined in the Proposed AMI Conditions, which was contained in PGE's March 7, 2007 AMI-related advice filing (subsequently docketed as UE 189).

The "Proposed Critical Peak Pricing Tariff" summary provides both background information on demand response potential and critical peak pricing (CPP) design considerations. The information includes a framework for a CPP tariff and an example of a CPP structure. PGE is committed to working with interested parties to develop a CPP tariff.

If you have any questions regarding this submittal, please contact Alex Tooman at (503) 464-7623

Sincerely,

Doug Kuns
Manager, Pricing and Tariffs

DK:lh

cc: UE 189 Service List

Encl.

Proposed Critical Peak Pricing Tariff

Summary

For several years PGE has had a strong interest in the appropriate implementation of demand response (DR) and meets with industry players to discuss their efforts to implement various forms of demand side response to meet their needs. The Demand Response Research Center (DRRC) defines DR as[1]:

Demand Response (DR) is the action taken to reduce load when:
- Contingencies (emergencies & congestion) occur that threaten supply-demand balance, and/or
- Market conditions occur that raise supply costs

DR typically involves peak-load reductions
- DR strategies are different from energy efficiency, i.e., transient vs. permanent

A successful demand response program would further the company objectives of reducing generation supply costs and increase options for customers to control their monthly electricity bills.

For this reason, PGE proposes to introduce a Critical Peak Pricing (CPP) tariff in timing with our AMI initiative in addition to looking into implementation of Direct Load Control in the company's Integrated Resource Plan (IRP) Action Plan.

Situation Analysis

PGE estimates a need to acquire over 700 MW of firm capacity in winter (including reserves), and approximately 500 MW firm capacity summer, by the year 2012.

Capacity Situation

PGE's long term capacity deficit is changing due primarily to two factors. In 2007, the Portland Westward generating plant is due to come on line for an increase in capacity by about 450 MW. However, power from some long-term contracts and hydro licenses are due to expire prior to 2012[2]. After considering the capacity brought by our proposed energy actions the net capacity gap is about 700 MW by 2012 (in a one-in-two year). Much of the gap is to satisfy planning reserves, i.e., our current 12% reserve is about 500 MW, half of which is planning reserves. We recognize Demand Response Load Control as a potential resource to supply some of this capacity.

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[1] Diamond, Rick and Piette, Mary Ann, Demand Response Research Center, Research Opportunity Notice, ***"Understanding Customer Behavior to Improve Demand Response Delivery in California",*** February 2, 2007.
[2] Stakeholder Dialogue No. 7, PGE 2007 Integrated Resource Plan, April 9, 2007.

From the IRP planning perspective there are several factors that impact customer's participation in demand response programs. The major factors are availability of capacity, regionally low prices, lack of market conditioning, prevalence of winter seasonal peak, and cost recovery.

- Availability of capacity – the Pacific Northwest is an energy constrained region, unlike most of the rest of the U.S. that is capacity constrained. This is due primarily to our hydro system, which is traditionally used for minute to minute load following. During times of short term need, it can deliver about twice as much energy as typically generated. However, this is changing as hydro availability is decreasing and demand is growing. In the next ten years, PGE believes it will be in a capacity constrained situation much like the rest of the country.
- Low prices – Utilities in the Northwest are relatively low cost providers. People moving in from other regions are particularly aware of this. From a bill perspective, there is less incentive to practice DR because of the lack of a noticeable difference in their bill for their efforts. Longer paybacks on their investments are not economically attractive.
- Market conditioning – There is a body of evidence indicating that external factors condition the market toward or away from participation in market trends, including utility DR programs[3]. For example, in grid areas that have experienced blackouts, or even rolling brownouts, and the media has brought attention to the causes, people are more sensitized to their role in the cause and therefore their role in the solution. DR programs in those areas are showing some measured success.
- Winter peaking programs – The most successful load control programs to date are for irrigation, air conditioning, and pool pump control. PGE does not have much irrigation load; however, the air conditioning load is growing. At the projected growth rates, in several more years the air conditioning load will cause a shift in seasonal peaking from winter to summer. When it does, the summer peak will have a needle peak load shape of very short duration compared to winter peaking.
- Cost recovery – On the surface it appears that because air conditioning peaks are of short duration, it is more difficult to recover fixed overheads and program costs when the number of hours used per year is very few. Capacity requirements generally can be acquired on the spot market; however, when contiguous regions are experiencing the same capacity constraints, such as on July 24, 2006 in the WECC, even expensive load control programs have a place in meeting reliability requirements.

In an effort to determine how much capacity is likely achievable by PGE customers, the Company commissioned Quantec, LLC to update the DR resource potential report. DR is categorized into Dispatchable and Non-Dispatchable resources. Dispatchable resources can be controlled remotely by the utility or a third party. Non-Dispatchable resources are primarily price driven and rely primarily on customer behavioral decisions which may or may not be enabled by technology that is pre-programmed to respond as the customer would. Their estimate of dispatchable DR is approximately 138 MW in winter, 113 MW of which is from Dispatchable Standby Generation (DSG); and 149 MW in summer, 125 MW of which is from DSG. Non-dispatchable, or "pricing programs" represent about 29 MW of winter peaking need and 28 MW of summer requirements.[4] See Tables 1 and 2 below.

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[3] Energy Information Administration, PowerDat, RMI.

[4] Quantec, LLC, "*Update of Demand Response Resource Potentials for PGE*", Final Report, January 18, 2006.

Table 1 - Dispatchable Demand Response

Season	Winter			Summer		
Strategy	**Dispatchable Space Heating**	**Dispatchable Water Heating**	**Dispatchable Standby Generation**	**Dispatchable Air Conditioning**	**Dispatchable Water Heating**	**Dispatchable Standby Generation**
Industrial	-	-	38	-	-	40
Commercial	-	-	72	1	-	80
Agriculture/ Utilities	-	-	4	-	-	5
Residential	10	15	-	18	5	-
Total	**10**	**15**	**113**	**19**	**5**	**125**

Table 2 - Non-Dispatchable Demand Response

Season	Winter		Summer	
Strategy	**TOU with CPP Adder**	**Demand Buyback**	**TOU with CPP Adder**	**Demand Buyback**
Industrial	-	14	-	14
Commercial	1	7	1	7
Agriculture/ Utilities	-	-	-	-
Residential	8	-	6	-
Total	**8**	**21**	**7**	**21**

Market Conditioning

There is a body of evidence indicating that external factors condition the market toward or away from participation in market trends, including utility DR programs[5]. For example, in grid areas that have experienced blackouts, or even rolling brownouts, and the media has brought attention to the causes, such as California, the Northeast, Utah and Florida, people are more sensitized to their role in the cause and therefore their role in the solution. DR programs in those areas are showing some measured success. The energy crisis of 2000-2001 in California is the classic example of the amount of media attention given to the situation. As a result, the follow-on California Statewide Pricing Pilot was able to capture customers' attention. In other regions where the causes have not been well publicized, customers are not sure that their participation in programs to reduce demand during peak periods will have much impact, e.g. Arizona and Nevada. Oregon's customers' market conditioning is toward green energy. Research shows that PGE's customers prefer renewable power and energy efficiency over all

[5] Energy Information Administration, PowerDat, RMI.

other sources of power[6]. This is demonstrated by their willingness to pay a premium for wind power and other sources of renewable generation, making them number one in the nation for green energy participation.

Dispatchable Resource

The IRP models "firm", or dispatchable, DR resources. These are resources that can be controlled remotely by the utility or other third party, and provide near instant reduction in demand. They include Dispatchable Standby Generation, Direct Load Control (DLC) of central electric space heating, electric water heating, and air conditioning. The number of pool pumps among PGE's customers is not considered to be large enough at this time to model separately.

PGE's resource plan includes the large amount of DSG available. DSG generators, when operating in parallel, act like a demand response resource, in that they supply most or all our customers' loads, removing these loads from the grid. All generators are parallel grid connected to first pickup the customer's load then supply any excess generation to the PGE system within 10 to 15 seconds. PGE's System Control Center (SCC) can dispatch all available sites on-line. Customers participating in the program receive a proposal for upgrading their generator system to full parallel operation. If the economics show this to be a cost effective site, PGE will pay for all the upgrades in paralleling switchgear, controls upgrades, emissions upgrades, power quality monitoring & metering system and the entire grid interconnection package, including relays, transformers and transfer-trip communications if required. After the installation, PGE pays for all maintenance for the generator and switchgear, all repairs for this equipment and all fuel for the generator. The customer agrees to pay for the power their facility uses, even if it is produced by the generator at their site.

Since direct load control programs can be implemented with or without the facilitation of an installed Advanced Metering Infrastructure (AMI), PGE will verify its estimates of response by including a call for demand side capacity resources, such as DLC, in the Capacity RFP planned as part of the IRP Action Plan.

Non-Dispatchable Resource

The reliability of non-dispatchable resources is considered to be unproven enough at this point in time to require exclusion from formal planning for firm resources in the IRP. When enough events are triggered over time and across varying circumstances, pricing driven demand response may provide a statistical level of reliability to begin modeling it in future planning.

Non-firm resources are reflected in the company's load forecast based on historical load changes. Non-firm, or pricing "programs", could provide 29 MW of capacity in winter, 8 MW of which could come from a residential CPP rate during winter peak hours and 7 MW of the 28 MW in summer[7]. In its initial form, the Advanced Metering Infrastructure (AMI) initiative that is currently before the Oregon Public Utility Commission (OPUC) allows a dynamic pricing structure to be implemented more easily with AMI. This is also supported by the National Association of Regulatory Utility Commissioners (NARUC) in their adoption of the Resolution

[6] Momentum Market Intelligence, *"Customer Preferences For IRP Portfolio Content: Is it Really All About Green Resources? Relevant Insight from Research Conducted with Residential, General Business, and Large Business Customers"*, April 5, 2006

[7] Quantec, LLC, *"Update of Demand Response Resource Potentials for PGE"*, Final Report, January 18, 2006

to Remove Regulatory Barriers to the Broad Implementation of Advanced Metering Infrastructure on February 21, 2007.[8]

AMI

For nearly ten years PGE has been evaluating and advancing various advanced metering technologies. The company built a Meter Data Consolidator (MDC) which is the critical head-end of an advanced metering system. The AMI team is preparing to complete full deployment throughout PGE's service territory in late third quarter 2009.

AMI is a system that enables the automated collection of meter data via a fixed network. It consists of three main components: solid-state electronic meters, a communication system or network, and a communication server that receives and stores data from the meter and, in a two-way system, sends commands to the meter.

PGE is pursuing AMI in order to attain operational and economic efficiencies, and provide improved services to our customers. It will also enable PGE to offer demand response such as CPP and other programs that become cost effective with AMI.

Advancement towards Market Transformation

On December 16, 2004, PGE presented to the OPUC a plan for demand side market transformation[9]. At that time we presented a long-term look at some steps to achieve commercialization of smart appliances with which peak demand control will be automatic. Parallel to the steps was development of an advanced metering infrastructure that provides support for dynamic pricing options.

Since the industry is still some time away from agreeing upon appliance standards, for example requiring water heaters to have the ability to be programmed to shut off during peak hours or during hours at the customers' preference (as can thermostats be programmed to regulate space heating and cooling), PGE is pushing toward the next step in the transformation in several ways by:

1. continued participation in the USDOE GridWise™ smart appliance research which has progressed to include sending price signals to appliances,
2. taking a more proactive role in communication protocol standard setting by working directly with appliance manufacturers, and
3. developing an experimental CPP tariff to exercise the capabilities of the proposed AMI.

Critical Peak Pricing (CPP)

The purpose of PGE's experimental CPP tariff is to push forward toward demand side market transformation. Critical Peak Pricing (CPP) is a form of time-of-use (TOU) rates, distinguished by the imposition of premium prices during limited predefined periods. CPP rates have been

[8] NARUC Winter Meeting, Washington D.C. February 2007, resolution sponsored by the Committee on Energy Resources and Environment.
[9] Hawke, Steve, V.P. Customer Service and Distribution, *"Non-Wires Alternatives for Meeting Utility Distribution and Transmission System Needs", Oregon Public Utility Commission Workshop,* December 16, 2004.

used to curtail electric demand during periods of low utility reserve margin, serious system emergencies, and market opportunity for power sales.

Curtailing electricity demand at will through price signals naturally requires a set of participating customers, whose behavior is well understood. Tests with these participants have sought to reveal the willingness of customers to participate in CPP programs, the price elasticity of demand for CPP participants, and the systems required to reliably obtain CPP curtailments.

As an alternative to price signaling through CPP or TOU rates, many utilities have sought demand reductions through direct load control programs, which are based on device controls and cash payments to participating customers. It is a substantial challenge to operate load control programs economically and equitably. Introducing price signals provides both utilities and customers with more flexibility.

California Experience and results from other Utility Programs[10]

Rates, including CPP rates, reflect differences in utility climates, resource requirements, and state policies. Because they depend upon customer behavior, the designs of CPP rates also reflect differences among utility customers. These many differences from one utility to another mean that the results of CPP experiences elsewhere can only be taken as a starting point for designing a CPP rate appropriate for Oregon. But California has provided one such starting point.

California's notable 2003-2004 Statewide Pricing Pilot (SPP) involved over 2,500 customers in a series of controlled tests across various utility territories, CPP rate designs, customer segments, customer information, and system technologies.

While the SPP was a series of tests, and was neither designed nor operated to commercial standards, it provided many lessons. Most notably, the SPP demonstrated that price signals can reduce demand. The price-elasticity of electricity demand was significant, reasonably stable over time and reasonably consistent within customer classes.

For example, California Climate Zone 2 (the Inland Coastal zone) constitutes about 48% of California, and is the California climate zone most similar to PGE's territory. In testing the CPP "fixed" version (that is, the critical peak period did not vary and customers were not offered enabling technology), the SPP confirmed Zone 2 average residential electricity demand reductions of 10% in the summer of 2003.

The SPP also indicated that enabling technology (e.g., programmable thermostats and pool pumps) and information (e.g., the online availability of customer usage data) substantially increased peak demand reduction above these levels. The SPP revealed that many customers reacted negatively to the complexity and variability of some CPP rates.

Finally, the SPP provided support for the belief that a sufficient set of customers can be recruited into a CPP program, and will remain in a CPP program because they find value in the experience. Customers will remain in such a program if they believe the program makes a difference: it either provides savings on their electric bill, more control over their home, or a

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[10] Boice, Craig, memo from Boice Dunham Group to PGE, February 23, 2007.

better community. Program participants come to understand that electricity has become considerably more expensive on certain days, and that they would benefit from becoming aware of these days, and changing their electricity use as they can.

The SPP results were encouraging, but the particular CPP rate designs tested in California were built around particular utilities' aims. The California utilities sought to achieve demand reductions on up to 75 summer hours of their choosing -- whether or not the temperature was extreme statewide. The utilities selected these "Super-Peak" days up to 24 hours in advance, and then notified participants they were coming. The rate differentials from off-peak to Super-Peak periods meant participants faced a difference between 7.8 cents/kWh off-peak to 73.8 cents/kWh Super-Peak in one test.

These SPP CPP rate design features reflected the particular circumstances of California utilities. The SPP provided substantial insight into how Californians would react to particular versions of CPP rates. However, the results in Oregon may differ. Not only is our CPP design different (e.g., we require a rate to address winter peaks as well as summer peaks), our design cannot depend primarily on air conditioning and pool pump curtailment.

Furthermore, customers in California have been conditioned differently than Oregonians. In the summer, air conditioning is mandatory for many businesses and households in California. California customers are used to an extremely complex inverted tier rate structure, frequent rate shocks, and utilities in severe financial distress. Californians experienced the SPP immediately after the Western Energy Crisis. Price signals for electricity have a somewhat different context in Oregon.

From similar tests conducted by other utilities (e.g., Puget Sound Energy, Anaheim, Ameren) we can recognize a similar basic pattern of customer interest, participation, and satisfaction. We see successful demand reductions. We note that utilities have designed rates suitable for their own climates, resource requirements, and state policies. Our proposal for a two-year experimental CPP tariff will allow us to identify the particular version of demand response rates most suitable for our circumstances in Oregon.

CPP Tariff

Much of the success of a CPP tariff with PGE customers will depend on how it is positioned with customers. PGE will have to rely on an approach that appeals to a customer set that has a preference for renewable energy. Short of a highly publicized Northwest energy crisis, market conditioning will take place over time, as the social conscience is engaged through the merged message of green power and demand side resources. The effort will be allegorical to PGE's early move into wind power at Vansycle Ridge. It was not considered to be cost effective at the time; however, it provided valuable information on how to proceed with subsequent wind projects as support for them gained momentum.

There is substantial evidence that CPP would provide relief from peak demand in summer, witnessed by the successful pool pump and air conditioning programs. However, there continues to be a need for more work around the winter peak, which is the season PGE shows the largest capacity gap. For example, CPP might be targeted toward customers with electric water heat to reduce the morning peak.

Plan

The Quantec study on Demand Response resource Potential suggests that in addition to the existing Demand Buyback (DBB) program, 8 MW of winter peaking capacity and 7 MW of summer peaking capacity can be acquired through a CPP rate design[11]. Looking at the load duration curve across the period of the IRP the critical winter peak hours are most likely in January or February, and may be limited to a few days per year, for about four or five hours per day. In summer, the peaks are higher and narrower, occurring on about the second or third consecutive day of temperatures above 90 degrees F. Therefore the resource required would provide capacity reductions driven by water heat and space heat in the winter and air conditioning in the summer.

This tariff proposal is not a pilot. It is an experimental tariff designed to be of a manageable size to lead the market with valuable information gained from the quantitative experiments.

Objectives

Demand response is a behaviorally driven resource[12]. To understand behavior it is as important to understand why and how as much as it is important to understand who and what[13]. To that end, the objectives address both the why/how questions and who/what questions.

1. First and foremost the tariff will test the resource gained through triggering the dynamic pricing events.
2. Summer impacts and winter impacts will be measured and compared.
3. Differences in impacts between customers with and without programmable thermostats will be measured.
4. To the extent possible, differences in impacts between enabling technologies, ie., programmable thermostats and water heater timers, and combinations of technologies will be measured.
5. To the extent possible, differences in impacts between customer segments will be measured.
6. Differences in impacts between TOU customers and non-TOU customers will be measured.
7. Sustainability of the impacts from year to year will be measured.
8. Customer satisfaction with the level of bill savings will be surveyed.
9. Customer awareness and commitment will be surveyed.
10. Customers will be surveyed as to why they participated, eg., what personal values, attitudes, policies, or economics influenced their decision. To the extent possible, non-participating customers may be surveyed to determine why they chose not to.
11. Customers will be surveyed as to what they took to reduce demand on CPP days.
12. Both the internal and external process(es) for triggering an event will be evaluated and incorporated into normal operating procedures.
13. Program messages and message media will be trialed and evaluated.

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[11] Quantec, LLC, "*Update of Demand Response Resource Potentials for PGE*", Final Report, January 18, 2006.
[12] Diamond, Rick and Piette, Mary Ann,Demand Response Research Center, Research Opportunity Notice, ***"Understanding Customer Behavior to Improve Demand Response Delivery in California",*** February 2, 2007.
[13] Ibid.

Table 3 - Required Cells for Measurement

	Large Single Family	Small Single Family	Multi-family	Small Non-Residential <30 kW
Summer Impact				
w/o Programmable Tstats	X	X	X	X
with Programmable Tstats	X	X	X	X
with Smart Tstats (year 2)	X	X	X	X
Winter Impact				
w/o Programmable Tstats	X	X	X	X
with Programmable Tstats	X	X	X	X
with Smart Tstats (year 2)	X	X	X	X

Scope

The rate option will be open to residential and small non-residential customers, i.e., Schedule 7 and Schedule 32.

Existing TOU customers will be able to participate by changing to the CPP price plan; it will not be combined with the TOU price plan at this time.

Customers will high winter usage, signifying potential electric space and/or electric water heat will be targeted. Customers with high summer usage signifying air conditioning load and/or electric water heat will also be targeted.

In order to gain enough participation to statistically measure the above objectives, and yet not stress the affected resources and systems noted below, the tariff will be open to 3,500 participants during the first two years. Random enrollments are expected to fill each cell with enough participants to provide statistically based measurements. Marketing may be adjusted to fill some cells. It is believed that the price structure will be enough incentive for customers to enroll in the tariff and participate in the voluntary curtailment events. Incentives may be used in year two if changes in the price structure do not yield the expected results.

Design

NOTE: The discussion below is an example of the design we are considering; however, final design will be proposed after inviting discussion with internal and external parties.

Based on PGE's plan for acquiring capacity resource, the CPP tariff will be used to provide capacity during extreme conditions. Extreme conditions include extended or intense weather conditions, acute market conditions, or utility emergencies. PGE's operating conditions do not warrant it to be used as a virtual base load plant that will be triggered on a near-constant basis.

PGE proposes a two-year experimental tariff that builds on the AMI as it is rolled out. Some things can be tested initially, such as the rate design. Beginning in year two, or as the AMI is stabilized and more capability can be added, other things may be tested, such as sending price signals to smart thermostats. This time frame also aligns with the time frame for the Request for Proposals for dispatchable demand side resources proposed in the 2007 Integrated Resource Plan Action Plan. This alignment allows technology requirements to be written to assure holistic system compatibility.

The initial design is intended to be somewhat simple in order to provide enough evaluative information to inform subsequent design changes.

CPP days will be called only in December, January and February during winter, and in July, August, and September in summer. Customers on the CPP pricing plan may pay a discounted basic rate in effect during those months or on CPP days. On CPP days, the winter event hours most likely are from 6:00 a.m. to 10:00 a.m. and from 5:00 p.m. to 8:00 p.m. The summer CPP hours most likely are 4:00 p.m. to 8:00 p.m. The price during those hours would be steeply increased from the basic rate.

Events will be called on week days only, not including holidays, up to three days in a row, and not more than five days per month. Notification will be given as late as 4:00 p.m. the day before an event. Without the ability to control events remotely, either by the utility (as in Direct Load Control) or by the customer, events will not be called the day-of. This is to avoid putting customers in the position where they would like to respond but have already left their premise for the day and are unable to respond. Day-of notification may be trialed in the second year when/if the company is able to provide premise technology that allows the customer to respond remotely.

Up to five days per month during the CPP months can be called, except in emergency conditions where it could be call more than five days per month.

The minimum enrollment period is 6 months.

Because customers would have the advantage of discounted basic rate pricing during all other hours, there would be no bill guarantee where any total yearly payments greater than the same usage on the basic rate would be refunded.

Only the CPP rate will be offered during the first year. Some customers may choose to use their own technology aid such as a water heater timer, or a programmable thermostat (PT). Based on results and customer feedback, some form of enabling technology may be offered to customers during the second year, such as programmable controllable thermostats (PCT) if price signals can be communicated directly to the thermostat. This would be intended to allow day-of notification of CPP event days.

To gain the most realistic results, events will be called only when certain criteria are met, including conditions that customers recognize ahead of time. Examples of conditions for calling a CPP event in winter could be:

- When the National Weather Service next day forecast average temperature, defined as the average of the daily forecast high and the daily forecast low temperature, is 32 degrees Fahrenheit, for the second day in a row.
- When emergency conditions exist.

Examples of conditions for calling a CPP event in summer could be:

- When the National Weather Service forecasts the next day's high temperature to be 90 degrees Fahrenheit for the third day in a row.

- When emergency conditions exist.

A cross-functional team within PGE is developing criteria for emergency response.

For purposes of this experimental tariff, the criteria will be "stress tested" when they are in effect. That is, when conditions exist where an event could be called, but for other market or economic reasons would not necessarily be called, they will be called up to the maximum limit of 5 days per month, and up to three consecutive days.

Notification will be through e-mail notification for general events, through customer knowledge of the NWS forecast conditions, and the designated media channels during emergency conditions.

Implementation

Implementation will commence after System Acceptance Testing (SAT) of the AMI installations are completed, and the first wave of regular installations are in place and operating. See schedule below.

Marketing

The above mentioned cells may be targeted through direct mail pieces and electronic means.

Human Resource and Systems Impacts

As with any customer-facing operation, several cross-functional support teams are required to build and maintain the internal infrastructure to operate the program. The resources and systems that will be most heavily relied upon are listed here.

1. Advanced Metering Infrastructure (AMI)
2. Billing
3. Business Decision Services
4. Corporate Communications
5. Customer Information System (CIS)
6. Customer Service
7. Information Technology (IT)
8. Legal/Contracting
9. Network Data Operations (NDO)
10. Program Operations
11. Power Marketing
12. Rates
13. System Control
14. Web Design team

Evaluation

The merits of continuing the tariff for long term duration is that it allows for downstream emerging technology, either as part of the AMI or as other enabling technology, to be incorporated into the program. The initial duration of the tariff is 2 years.

At that time the evaluation will recommend whether to:

- Expand the program as is, or with minor tweaks,

- Make major changes to the program in order to be successful, or
- Discontinue the program until customer perceptions or market conditions warrant reentering.

Schedule

To meet the needs of the AMI scoping plan, the following schedule is required for expedited implementation of the experimental tariff. It will require a high priority from the impacted resources and systems in order to meet the stated timeframe,

February 2007 – preliminary design
March-September – File IRP, IRP Action Plan, AMI conditions/scoping plan
October 2007 – file CPP tariff
January-September 2008 – ready internal systems for implementation
October-November 2008 – Enroll CPP participants
December 2008-February 2009 – Winter events
July-September 2009 – Summer events
October-November 2009 – preliminary evaluation
December 2009-February 2010 – Winter events
July-September 2010 – Summer events
October-December 2010 – final evaluation and recommendation

Financial Resources

For financial estimation the program life of the experimental tariff was extended five years, with residual benefits over the 20 year life of the AMI. Using the analytical tool provided in the AMI Scoping Plan response, the total 20-year real cost of this design in 2007$, including additional employee or contract resource, is estimated to be approximately $10.2 million without smart thermostats ($1.7 million in the first two years); and $15.0 million with smart thermostats, ($2.0 million in the first 2 years). The 20-year real NPV is $9.6 million without smart thermostats, and $14.4 million with smart thermostats.

Assumptions include 3,500 participants for years 1 and 2, and increasing to over 12,000 in year three. The amount of reduction per node is 0.52 kW without smart thermostats which is more than 10% reduction in average household use. An additional 25% reduction was added to the scenario with smart thermostats based on the average results of the California SPP[14]. Avoided capacity costs are $72.1/kW/yr. It is also assumed that in the early years the costs are not expected to be fully offset by the benefits.

[14] Faruqui, Ahmed, and George, Stephen, "Quantifying Customer Response to Dynamic Pricing", *The Electricity Journal*, May 2005, Vol. 18, Issue 4, page 53.