**Portland General Electric Company**
*121 SW Salmon Street • Portland, Oregon 97204*
*PortlandGeneral.com*

September 15, 2017

**Via Email**
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High Street, Ste. 100
PO Box 1088
Salem, OR 97308-1088

**Attn: OPUC Filing Center**

Re: **UM 1657 PGE Reply Comments – Smart Grid Report**

Enclosed for filing are Portland General Electric's Reply Comments regarding its 2016 Smart Grid Report submitted in Docket Number UM 1657. PGE also includes the following Attachments:

- Attachment A: Advice Filing 17-18 New Schedule 25 Nonresidential Direct Load Control Pilot Rider and New Schedule 26 Nonresidential Demand Response Pilot Program Rider
- Attachment B: AMI Operational Savings Report (July 1, 2011 to December 31, 2011)
- Attachment C: AMI Operational Savings Report (January 1, 2012 to June 30, 2012)
- Attachment D: PGE Scoping Plan for AMI Benefits

This document is being filed by electronic mail with the Filing Center.

If you have any questions or require further information, please contact me at (503) 464-8929. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com

Sincerely,

Stefan Brown, Manager
Revenue Requirements

SB/sp

Enclosure

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 1657**

| | |
|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY<br><br>Annual Smart Grid Report | REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY |

Portland General Electric Company (PGE) submits these reply comments in response to comments submitted by the Public Utility Commission of Oregon (OPUC) Staff and the Oregon Department of Energy (ODOE) regarding PGE's 2017 Smart Grid Report (the Report).[1,2] PGE appreciates the input it received on the Report and looks forward to continued collaboration around future Reports and Smart Grid development in Oregon. PGE's Reply Comments are organized into the following sections:

Section 1. Demand Response

Section 2. CET

Section 3. Distribution System Planning

Section 4. Advanced Metering Infrastructure (AMI)

Section 5. Energy Storage

Section 6. Conclusion

[1] Staff's Comments filed August 11, 2017: http://edocs.puc.state.or.us/efdocs/HAC/um1657hac165319.pdf
[2] ODOE's Comments filed August 11, 2017: http://edocs.puc.state.or.us/efdocs/HAC/um1657hac161850.pdf

## Section 1. Demand response

Energy Partner Pilot

OPUC Staff, in its comments, raised multiple questions about PGE's Energy Partner Demand Response Pilot:

1. Provide PGE's opinions of and response to Navigant's analysis on future opportunities for the pilot; and
2. Provide the results of the May 2017 RFP for vendors to provide new opportunities for nonresidential customers and describe the strategy moving forward.

ODOE, in its comments, also provided the following suggestion:

1. ODOE encourages PGE to consider lower minimum thresholds for participating in the Energy Partner Pilot (duration and load requirements) in order to increase participation.

PGE responds as follows. Earlier this year, EnerNOC informed PGE it would no longer be doing business in the Pacific Northwest and would opt out of its contract with PGE to provide the aggregator demand response (DR) services under the Energy Partner Program. PGE has taken this opportunity to review existing programs (including Schedule 77) and revise them to create new programs able to meet PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products.

The new programs are based upon the learnings from the Energy Partner evaluations conducted by Itron, market research from Hansa, customer interviews, focus groups, and Navigant reports on these programs. Across the research, some common themes emerged:

- The DR portfolio could benefit from having a variety of offerings;
- There needs to be more flexibility in programs;
- Segments of our customer base (particularly in our commercial sector) are under-served; and

- Offerings need to better address customer business needs.

From the study, PGE concluded that the new program should differ from the original Energy Partner program in these ways:

- This program should be administered directly by PGE, with support from a program implementer and technology integrator/demand response management system (DRMS) provider.
- The Energy Partner program should be offered through two tariffs – Schedule 25 and 26. Schedule 25 provides nonresidential customers with a turnkey, direct load control program, similar to Schedule 5 for our residential customers. Schedule 26, which more closely resembles Schedule 77, provides a much greater diversity of participation levels, allowing customers to select differing availability periods, notification times, and maximum event hours. Schedule 26 will also allow customers with multiple points of delivery (POD) the ability to self-aggregate their PODs.

This new program design and its accompanying tariffs will open up new opportunities to expand the DR market. To increase flexibility, customers will be able to have increased capacity commitments without the long availability windows (10 hours under EnerNOC) and/or short notification windows (10 minutes previously). Small and medium sized businesses will be able to participate through either a turnkey thermostat offering or through a curtailable tariff with the flexibility that meets their needs. Campuses, a historically underserved market due to eligibility requirements and costs, will be able to aggregate their meters to participate without having to incur high upfront costs across smaller sites.

On September 1, 2017, PGE submitted a new nonresidential direct load control pilot and a new nonresidential demand response pilot (Schedule 25 and 26, respectively), which includes a summary of our proposed pilot changes, the redesign strategies we are adopting, and a discussion of cost-effectiveness. The Advice Filing has been provided as Attachment A.

Smart Thermostat Demand Response Pilot

In Staff's comments, they provided the following recommendations on PGE's smart thermostat demand response pilot:

- Be more aggressive on outreach. By 7/1/18 present partnership w/ ETO;
- Follow Cadmus recommendation to expand the program;
- More robust customer verification process to encourage customers to participate; and
- Update planning assumptions.

PGE agrees with Staff's comments, and has stated the same in our UM 1708 comments. PGE appreciates Cadmus's recommendations and is making a variety of efforts to increase program participation and update planning assumptions accordingly. These include:

- On July 18, 2017, we filed for reauthorization for the pilot, which includes changes to the schedule and tariff. The modifications allow for more open events and time windows for events. They also allow separate vendors (e.g., Honeywell, EcoBee, etc.) to participate in the pilot. We launched a program expansion on August 31, 2017 with Whisker Labs and have already enrolled over 400 non-Nest thermostats.
- We are looking for and building opportunities with ETO in several capacities. First, we are auto-enabling all thermostats enrolled through Whisker Labs for efficiency benefits. This essentially will serve as a recruitment vehicle for ETO efficiency incentives. Second, we are co-promoting thermostats with the ETO (Nest and EcoBee) for customers to learn about both PGE and ETO's incentives together. These collaborative efforts have been successful, and we will continue to explore opportunities to build a more positive customer experience.

Additional pilot information generally can be found in Docket UM 1708.[3]

## Section 2. Customer Engagement Transformation

In Staff's comments, Staff requested that PGE provide additional information on how adaptable the systems and processes the Customer Engagement Transformation program (CET) is updating will be to future program developments (e.g., incorporating future demand-side management or distributed energy resource (DER) programs into the system).

The new Customer Information System (CIS) and the Meter Data Management system (MDMS) will provide a more adaptable platform for standardized and streamlined transfer of data, improving the effort to implement and manage PGE's DR programs.

The Oracle data schema supports configuring rates and the grouping of intervals and associated pricing more easily than today. The time to configure the rates, interval readings, and interval pricing is significantly reduced.

In some cases, programmatic features will rely on functionality outside of the CIS. These programmatic features, such as enrollment, billing, and un-enrollment, will vary in expense and time to implement based on the complexity of the program being designed. For example, controlling appliances is beyond the scope of the CIS billing system and would be dependent on vendor support. As another example, communications to residential and small business customers about their bills, including interval usage, is currently supported by the web-based Energy Tracker product. Reporting and/or Web presentment of the customer's interval usage, beyond what is provided by the Energy Tracker tool today would result in additional labor, maintenance, and costs.

[3] UM 1708 is available at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19228.

The new CIS & MDSM will provide a more systematic approach to program management, including:

- Improving insight into customer enrollment and un-enrollment in DR programs and the timing associated with the enrollment process;
- Improving clarity of the configuration of DR programs, such as account, premises and meter set-up;
- Allowing for a more streamlined and timely process for developing and setting-up new rate schedules;
- Allowing for transparency of data tracking between the CIS and MDMS for PGE employees;
- Capturing interval data for all customers in a single application with more robust and automated validation processes; and
- Improving timing coordination with PGE's third-party vendors who assist PGE with the execution of DR programs to determine the best load shifting and load reduction strategies as well as everyday energy saving opportunities for our customers.

The CIS and MDMS build the foundation upon which PGE can develop future programs. These systems are more widely used across utilities, both nationally and globally, so the changing needs of the industry are more easily updated in the system through upgrades.

## Section 3. Distribution System Planning

In Staff's and ODOE's comments, they provided a number of comments/questions regarding distribution system/resource planning (DRP). Specifically, Staff asked PGE the following:

1. Because the Commission supports conducting an investigation into the distribution system planning in PGE's 2016 integrated resource plan (IRP – LC 66), Staff anticipates the primary discussions and efforts resulting from that specific recommendation.

Because of this, Staff asks PGE in future Smart Grid Reports to summarize developments in DRP efforts that arise from Staff's recommendation in LC 66.

PGE agrees to continue to report the DRP efforts as directed through LC 66 and report updates in future Smart Grid Reports through UM 1657.

2. Both Staff and ODOE requested that PGE discuss how PGE's transmission and distribution (T&D) Analytics pilot can be used to inform a future DRP.

Without the enhanced visibility and a more granular view of load/resource data, PGE will need to maintain additional margin (capacity, voltage bandwidth, system protections, etc.) in system capability to account for changing operating conditions to support customers' reliability and power quality expectations. This added margin impacts how we optimize the system and our ability to secure locational value from DERs. By advancing T&D's data collection and analytic capabilities, including systems to leverage real-time data streams, PGE will create an opportunity to develop workgroups and functions to help manage and optimize PGE's infrastructure and resources. The T&D Analytics pilot gives PGE a more granular-level look at system impacts of DER deployments (e.g., premises-level voltage alarms), which could affect a DRP process regarding when and where to deploy DERs (to yield maximum benefits) or locational costs to limit or mitigate problems associated with DER deployment. Establishing the tools, people, and processes to operationalize enhanced analytics in T&D are fundamental to integrating DERs into the DRP.

3. ODOE requested that PGE describe how it envisions DRP aligning or otherwise interacting with existing regulatory dockets [e.g., Resource Value of Solar (UM 1716), Energy Storage (UM 1751), Transportation Electrification (UM 1811), and Integrated Resource Plan (LC 66)].

In Section 2.7b of the Smart Grid Report, PGE identified seven components we believe would be required to develop a DRP:

- Identify constraints to DER within the distribution system (feeder hosting capacity analysis);
- Determine where and when DERs are most beneficial to the system;
- Forecast feeder-level DER adoption;
- Develop a T&D operations roadmap;
- Pilot innovative solutions and models;
- Engage in a public/regulatory process; and
- Report preparation.

As indicated in the Report, many subjects are being encountered across various dockets (e.g., locational value, cost-effectiveness, etc.): UM 1716, UM 1751, and UM 1811. PGE believes that the work going on in existing regulatory dockets related to programs/technologies (e.g., value of solar, energy storage, transportation electrification) could feed technology-specific information into a DRP to support the development of the processes described above. Current dockets and future DER dockets would help inform value streams and applicable forecasting efforts. PGE already includes smart grid technologies as viable resources in the IRP as they mature, similar to the way cost-effective energy efficiency and demand response are considered. As a DRP identifies resources that may fill a system resource need, they will be evaluated as a part of the continuing conversation between program/system planners and the IRP team and, when appropriate, will be included in PGE's IRP process.

Further, the next IRP will incorporate and leverage the work in these dockets to forecast DERs. The current methodology for forecasting and incorporating demand-side and distributed resources, and the alignment with load forecasting, will be discussed during IRP public roundtable meetings with stakeholders. PGE will explore opportunities to improve the methodologies for leveraging information from various dockets through the IRP process.

4. ODOE requested that PGE describe what near term steps could be taken to move PGE further in developing locational net benefit analysis even as industry standards are still being developed.

PGE is standardizing the method by which it analyzes the benefits and cost of grid investments, using methods and inputs into these analyses that are consistent across departments. Thus, the "locational value" concept is affecting the investment analyses for projects and initiatives featured in several dockets, including PGE filings LC 66 (IRP), UM 1751/1856 (Energy Storage), and UE 319 Exhibit 800 (T&D testimony in PGE's 2018 general rate case). PGE appreciates the stakeholder input received to date and looks forward to refining and enhancing our processes for determining locational value of DERs. Worth noting, however, PGE recently filed a draft potential evaluation through the Energy Storage Dockets (UM 1751/UM 1856) that demonstrates PGE's proposed approach to evaluating locational value of storage. We believe that this methodology could be valuable in evaluating other DERs in the future.

## Section 4. Advanced Metering Infrastructure (AMI)

ODOE would like to see a quantification of both the direct benefits associated with AMI Deployment (e.g., elimination of PGE's direct labor and fuel costs associated with truck rolls for manual meter reads) and any associated indirect benefits (e.g., benefits to grid operation, improved customer service, etc.).

PGE's Response

PGE originally provided a response to this comment in PGE reply comments filed August 26, 2016 in UM 1657. In accordance with Commission Order No. 08-245, PGE submitted two reports on operational savings derived from PGE's AMI system. These reports were submitted on July 31, 2012 and November 2, 2012, and are provided as Attachments B and C to this response.

On July 27, 2007, PGE submitted a Scoping Plan (i.e., PGE Exhibit 103 in Docket No. UE 189), which was a very preliminary analysis of the informational benefits to be derived from AMI. The Scoping Plan is provided as Attachment D to this response. Since then, PGE has not performed any subsequent analysis of the overall informational benefits to be derived from AMI. Instead, PGE has focused on implementing applicable pilots and/or programs and evaluating their costs and benefits on an individual basis.

## Section 5. Energy Storage

ODOE expressed support for PGE's demonstration solar plus storage project with the City of Portland (City) at Fire Station No. 1. ODOE encourages PGE to consider an agreement with the City that allows PGE to utilize the system for multiple use cases (beyond DR).

Like ODOE, PGE is interested in leveraging the battery storage device to be installed at Fire Station No. 1 to explore a host of use cases, including but not limited to DR or peak shaving. Once the City has finalized its choice and design of battery system, the extent of available use cases will become more certain. Importantly, the battery installed at Fire Station 1 will be owned by the City of Portland; accordingly, the City – and not PGE – has ultimate authority on how the battery may be used. PGE, however, is actively exploring opportunities through the Energy Storage Dockets (UM 1751/1856) that would allow PGE to utilize customer-sited energy storage devices for grid services.

## Section 6. Conclusion

PGE believes the 2017 Smart Grid Report filing has met the requirements established by previous Commission Orders[4] and requests the Commission to accept this report. PGE appreciates the input and collaboration of Staff and other stakeholders on this report. PGE looks forward to continued collaboration around future reports and smart grid development in Oregon.

Dated this 15th day of September, 2017

Stefan Brown
Manager, Regulatory Affairs
Portland General Electric
121 SW Salmon Street, 1WTC0306
Portland, OR 97204
503.464.8929

[4] See Commission Order No. 12-158 established in Docket No. UM 1460 and Commission Order No. 16-504 established in Docket No. UM 1657.

## Attachment A.

## Advice Filing 17-18, NEW Schedule 25 Nonresidential Direct Load Control Pilot and NEW Schedule 26 Nonresidential Demand Response Pilot Program

**Portland General Electric Company**
*121 SW Salmon Street • Portland, Oregon 97204*
*PortlandGeneral.com*

September 1, 2017

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

**RE: Advice No. 17-18, NEW Schedule 25 Nonresidential Direct Load Control Pilot Rider and NEW Schedule 26 Nonresidential Demand Response Pilot Program Rider**

Portland General Electric Company (PGE) submits this filing pursuant to Oregon Revised Statutes 757.205 and 757.210, and Oregon Administrative Rule (OAR) 860-022-0025, for filing proposed tariff sheets associated with Tariff P.U.C. No. 18, with a requested effective date of **October 11, 2017**:

Seventeenth Revision of Sheet No. 1-1
Original Sheet No. 25-1
Original Sheet No. 25-2
Original Sheet No. 25-3
Original Sheet No. 25-4
Original Sheet No. 26-1
Original Sheet No. 26-2
Original Sheet No. 26-3
Original Sheet No. 26-4
Original Sheet No. 26-5
Original Sheet No. 26-6
Original Sheet No. 26-7
Original Sheet No. 26-8

PGE hereby submits Schedule 25 Nonresidential Direct Load Control Pilot Rider and Schedule 26 Nonresidential Demand Response Pilot Program Rider. This pilot is expected to be conducted through September 30, 2020. PGE will use the existing deferral associated with nonresidential demand response in Docket UM 1514 to defer costs associated with the pilots and will seek reauthorization of the deferral later in September. PGE will seek amortization of the deferred amounts in a future Commission proceeding. After amortization is authorized, PGE proposes to recover incremental costs to implement this pilot through prices in the existing Schedule 135, Demand Response Cost Recovery Mechanism.

PGE proposes to implement these nonresidential demand response pilots to replace both PGE's Schedule 77 Firm Load Reduction Program and Automated Demand Response Pilot. It is likely that customers on those programs will enroll in the Schedule 26 nonresidential demand response pilot and will continue providing demand response to PGE.

The Commission, through the 2016 IRP, strongly encouraged PGE to deliver cost effective Demand Response (DR), including DR from the Commercial and Industrial market segments. Currently, there are two programs for those market segments:

| Program | Approximate Committed Demand Reduction | Operating Period |
|---|---|---|
| Schedule 77 (curtailable tariff) | 1.8 MW | Winter – Dec, Jan & Feb<br>Summer - July, Aug & Sept |
| Energy Partner (automated DR) Partnering with EnerNOC | 8 MW (Winter)<br>11 MW (Summer) | Winter – Dec, Jan & Feb<br>Summer - Jun, July, Aug & Sept |

Earlier this year, EnerNOC informed PGE they were leaving the Pacific Northwest and would be opting out of their contract with PGE to provide the aggregator DR services under the Energy Partner program. PGE has taken this opportunity to review the existing programs and revise them to create a program able to meet PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products. The submitted tariffs are the cornerstone of these new programs.

The new programs are based upon the learnings from the Energy Partner evaluations conducted by Itron, market research from Hansa, customer interviews, focus groups, and Navigant reports on the these programs. Across the research, some common themes emerged:

- PGE needs to have a variety of offerings;
- There needs to be more flexibility in programs;
- Important segments of our customer base (particularly in the commercial sector) are under-served; and
- Offerings need to better address customer business needs.

As suggested in the submitted tariffs, the new program design will differ from the original Energy Partner program in a number of ways, as outlined below.

First, this program will be administered directly by PGE to its customers, with support from a program implementer and technology integrator/DRMS provider. The primary reason PGE took this approach was to allow PGE the flexibility to offer a variety of products and potentially make adjustments to those products in the future. The EnerNOC program was very rigid in its parameters and this was identified as one of the barriers to adoption. The secondary reason for PGE to work directly with customers is to ensure resilience of the portfolio. With the loss of EnerNOC, new contracts and new technology will need to be put in place for our current customers. We want to be sure this will not happen again. Running the program in house also gives PGE and its implementer the ability to better bundle and/or cross-market Energy Partner with other offerings, such as: energy efficiency, renewables, storage, or dispatchable standby generation.

The Energy Partner program is now offered through two distinct tariffs. The first, Schedule 25, provides nonresidential customers with a turnkey, direct load control program, similar to Schedule 5 for our residential customers. This will provide an easy opportunity for our commercial customers to participate, while getting the value added services associated with one or more smart thermostats. The second tariff, Schedule 26, more closely resembles Schedule 77, our current curtailable tariff. Schedule 26, however, provides a much greater diversity of participation levels, allowing customers to select differing availability periods, notification times, and maximum event hours. Schedule 26 will also allow customers with multiple points of delivery (POD) the ability to self-aggregate their PODs.

This new program design and its accompanying tariffs will open up new opportunities to expand the market. Existing and new customers that were previously averse to the long availability windows (10 hours under EnerNOC) and/or short notification window (10 minutes previously) will be able to have increased capacity commitments under less onerous conditions. Small and medium businesses will be able to participate through either a turnkey thermostat offering or through curtailable tariff with the flexibility that meets their needs. Campuses, a historically underserved market, will be able aggregate their meters to participate without having to incur high upfront costs across smaller sites.

In order to run this program, PGE has contracted with CLEAResult to administer the marketing, sales, and implementation of the program. Enbala Corporation has been separately contracted to provide the technology integration and the Demand Response Management System (DRMS). Both contractors were selected through via an open RFP. These contractors were also selected for the multifamily water heater demand response pilot, potentially providing a place for synergies in multi-tenant buildings.

In summary, new program is designed to address both the needs of PGE's nonresidential customers while helping to grow a resilient and flexible demand response portfolio to serve our capacity needs. A short memo cannot fully explain the complexity of this program nor the tradeoffs. It is our wish to meet with Commission Staff to explain how this program will enable PGE to meet both of our demand response goals.

This filing includes the following attachments:

Attachment A – Cost Effectiveness Discussion

Attachment B - Commercial & Industrial Demand Response Program Redesign from Navigant

Attachment C – Demand Response Final Report and Presentation from Hansa

Work papers providing the prices for Schedule 25 and 26 are provided in Excel format.

Following each pilot year, PGE will generate a pilot evaluation to share with stakeholders; the evaluation will include various metrics on customer participation, demand response capacity, and data gaps that emerge from the pilot.

To satisfy the requirements of OAR 860-022-0025, PGE responds as follows:

PGE will seek amortization of the deferred amounts in a future Commission proceeding. PGE proposes to recover incremental costs to implement this pilot through prices in Schedule 135, Demand Response Cost Recovery Mechanism. Schedules 25 and 26 do not increase, decrease or otherwise change existing retail rates or have anything other than a de minimis impact on revenues.

Should you have any questions or comments regarding this filing, please contact Rob Macfarlane at (503) 464-8954.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing and Tariffs

Enclosures

# PORTLAND GENERAL ELECTRIC COMPANY
## TABLE OF CONTENTS
## RATE SCHEDULES

# SCHEDULE 25
# NONRESIDENTIAL DIRECT LOAD CONTROL PILOT RIDER

## PURPOSE

This direct load control pilot is a demand response option for eligible nonresidential Customers. The direct load control pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Customers for Direct Load Control Events. The pilot is expected to be conducted from November 1, 2017 through September 30, 2020.

## DEFINITIONS

Central Air Conditioning – air conditioner tied into a central ducted forced air system.

Direct Load Control – a remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Customer's heating or cooling through the Customer's Qualified Thermostat in order to reduce the Customer's energy demand.

Direct Load Control Event – a period of time in which the Company will provide direct load control.

Ducted Heat Pump – heat pump heating and cooling system hooked into a central ducted forced air system.

Electric Forced Air Heating – an electrical resistance heating system tied into a central ducted forced air system.

Event Notification – the Company will issue a notification of a Direct Load Control Event to participating Customers. Participating Customers must choose at least one method for receipt of notification. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company's website.

Event Season – the pilot has two event seasons: the Summer Event Season and the Winter Event Season.

Holidays – the following are holidays for purposes of the pilot: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.



PROPOSED TARIFF DO NOT BILL

**SCHEDULE 25 (Continued)**

DEFINITIONS (Continued)

Summer Event Season – the summer event season includes the successive calendar months June through September.

Winter Event Season – the winter event season includes the successive calendar months November through February.

Qualified Thermostat – thermostats that are Company-approved and listed on PortlandGeneral.com.

**AVAILABLE**

In all territory served by the Company.

**APPLICABLE**

Subject to selection by the Company, up to 10,000 Qualified Thermostats from eligible nonresidential Customers may elect to participate in the pilot. The Company will limit participation to 10,000 Qualified Thermostats. This program is available to eligible Customers on nonresidential schedules that elect to enroll. Customers will remain on their base schedule and will be eligible for the incentives described in this schedule.

**ELIGIBILITY**

Eligible Customers must have a Network Meter. Customers must have a Qualified Thermostat connected to the internet and the heating or cooling system at the Customer's expense, except as provided in the Incentives. To participate in the Winter Event Season, the Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Customer must have Central Air Conditioning or a Ducted Heat Pump.

**DIRECT LOAD CONTROL EVENT**

Direct Load Control Events occur for one to five hours. The Company may call two events per day, but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only in the following months: November, December, January, February, June, July, August, and September. Direct Load Control Events will not be called on weekends or Holidays. Reasons for calling events may include, but are not limited to: energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. The Company will call no more than 150 event hours per Event Season.

## SCHEDULE 25 (Continued)

### ENROLLMENT

The Customer may enroll at any time, but must participate for the minimum number of hours described in the incentive section.

### INCENTIVE

Participating Customers receive a Qualified Thermostat for signing up for the direct load control pilot. A Customer may receive multiple Qualified Thermostats for separate spaces subject to verification by the Company and at the Company's discretion. In addition, Customers receive $60 per Qualified Thermostat for each Event Season they participate. A Customer participating in all Event Seasons receives $120 per Qualified Thermostat per pilot year. Incentives are paid to the Customer with a check, bill credit, or generic gift card. To receive payment for an Event Season, the Customer must participate in at least 50% of the event hours for which the Customer is eligible to participate in that Event Season.

### SPECIAL CONDITIONS

1. The Customer may terminate service under this pilot at the next regularly scheduled meter reading if the Customer provides the Company two weeks' notice prior to the next regularly scheduled meter read date.

2. Customers that reenroll in the program are not eligible for a second Qualified Thermostat for signing up. A Customer continuing service at a new location is not considered a new enrollment.

3. If the participating Customer moves to a different location, the Customer may continue participation if the new location meets the eligibility requirements.

4. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

5. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from AC Cycling or changing the thermostat set point.

6. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion.

7. The provisions of this schedule do not apply for any time period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service schedule and associated charges.



PROPOSED TARIFF DO NOT BILL

**SCHEDULE 25 (Continued)**

SPECIAL CONDITIONS (Continued)

8. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, for poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation.

**TERM**

This pilot term is November 1, 2017 through September 30, 2020.

## SCHEDULE 26
## NONRESIDENTIAL DEMAND RESPONSE PILOT PROGRAM RIDER

### PURPOSE

This schedule is an optional supplemental service that provides participating Large Nonresidential Customers incentives for reducing a committed amount of load at the request of the Company. Under this tariff, the Customer provides a Firm Load Reduction Commitment that the Company calls at any time according to the conditions listed below. The pilot is expected to be conducted from November 1, 2017 through September 30, 2020.

### AVAILABLE

In all territory served by the Company.

### APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. Participating Customers must execute a Schedule 26, Firm Load Reduction Agreement (Agreement) to participate in this program. The Agreement specifies the Customer's Firm Load Reduction Commitment and selected Firm Load Reduction Options.

### CUSTOMER ENROLLMENT

Qualified Customers must enroll at least one week prior to the nomination month.

At the time of enrollment, for each event window, the Customer chooses the load reduction amount, advance-notice option, and maximum event hours per season option. First-time participants can also opt-in for a commissioning test.

Within five days of enrollment, the Company will confirm receipt of the PODID(s) the Customer intends to enroll under this schedule and the Company or its representatives will send a signed Agreement to the Customer's representative. The Customer may choose to aggregate PODIDs.

Each Agreement will automatically renew for successive annual terms on January 1st of subsequent calendar years unless the Customer elects to terminate such Agreement by notifying PGE prior to January 1st or this Schedule is withdrawn, revoked or otherwise terminated. A customer may also choose to change their contracted participation options by notifying PGE prior to January 1st.

SCHEDULE 26 (Continued)

**CUSTOMER PARTICIPATION OPTIONS**

Customers are offered three participation options: Option 1 provides that the Customer participates for all eight months of the contracted program year. Options two and three offer the Customer summer or winter seasonal participation. In the second option the Customer participates for four months in the summer – June, July, August and September. The third option is the Customer participates for four months in the winter – November, December, January and February. Customers select one of the three options at the time of enrollment.

| Customer Option | Participation Months | Number of Months Participating |
|---|---|---|
| 1 | Nov, Dec, Jan, Feb, Jun, Jul, Aug, Sep | Eight-month – both seasons |
| 2 | Jun, Jul, Aug, Sep | Four-month seasonal – summer |
| 3 | Nov, Dec, Jan, Feb | Four-month seasonal – winter |

**FIRM LOAD REDUCTION OPTIONS**

Several firm load reduction options are available to Customers in the Reservation Price Section: Options include differing maximum event hours per season, notification periods, and event windows. For each event window (time period for an event) per season, the Customer must choose only one option or choose not to participate in that event window. For example, for the summer 11 am to 4 pm event window, the Customer can choose an 18 hour ahead notification period with a maximum of 20 event hours per season, but cannot make any other selections for the summer 11 am to 4 pm event window.

**RESERVATION PRICE**

**20 Event Hours Maximum per Season**
Monthly Payment per kW

| | Notification Period | | |
|---|---|---|---|
| | 18 hours | 4 hours | 10 minutes |
| Summer (June - September) | | | |
| 11 am -4 pm | $1.54 | $1.64 | $1.75 |
| 4 pm - 8 pm | $1.78 | $1.90 | $2.02 |
| 8 pm - 10 pm | $0.36 | $0.38 | $0.41 |
| All summer windows | $3.68 | $3.93 | $4.18 |
| Winter (November - February) | | | |
| 7 am - 11 am | $1.16 | $1.24 | $1.32 |
| 11 am -4 pm | $0.67 | $0.71 | $0.76 |
| 4 pm - 8 pm | $1.90 | $2.03 | $2.15 |
| 8 pm - 10 pm | $0.67 | $0.71 | $0.76 |
| All winter windows | $4.39 | $4.69 | $4.99 |



PROPOSED TARIFF DO NOT BILL

**SCHEDULE 26 (Continued)**

RESERVATION PRICE (Continued)

**40 Event Hours per Season**
Monthly Payment per kW

| | **Notification Period** | | |
|---|---|---|---|
| **Windows** | **18 hours** | **4 hours** | **10 minutes** |
| Summer (June - September) | | | |
| 11 am -4 pm | \$2.30 | \$2.46 | \$2.62 |
| 4 pm - 8 pm | \$2.67 | \$2.86 | \$3.04 |
| 8 pm - 10 pm | \$0.54 | \$0.58 | \$0.61 |
| All summer windows | \$5.52 | \$5.89 | \$6.27 |
| Winter (November - February) | | | |
| 7 am - 11 am | \$1.74 | \$1.86 | \$1.97 |
| 11 am -4 pm | \$1.00 | \$1.07 | \$1.14 |
| 4 pm - 8 pm | \$2.84 | \$3.04 | \$3.23 |
| 8 pm - 10 pm | \$1.00 | \$1.07 | \$1.14 |
| All winter windows | \$6.58 | \$7.03 | \$7.48 |

**80 Event Hours Maximum per Season**
Monthly Payment per kW

| | **Notification Period** | | |
|---|---|---|---|
| | **18 hours** | **4 hours** | **10 minutes** |
| Summer (June - September) | | | |
| 11 am -4 pm | \$3.06 | \$3.27 | \$3.48 |
| 4 pm - 8 pm | \$3.55 | \$3.80 | \$4.04 |
| 8 pm - 10 pm | \$0.72 | \$0.77 | \$0.82 |
| All summer windows | \$7.34 | \$7.84 | \$8.34 |
| Winter (November - February) | | | |
| 7 am - 11 am | \$2.31 | \$2.47 | \$2.63 |
| 11 am -4 pm | \$1.33 | \$1.42 | \$1.51 |
| 4 pm - 8 pm | \$3.78 | \$4.04 | \$4.30 |
| 8 pm - 10 pm | \$1.33 | \$1.42 | \$1.51 |
| All winter windows | \$8.76 | \$9.35 | \$9.95 |



PROPOSED TARIFF DO NOT BILL

**SCHEDULE 26 (Continued)**

**COMMITTED LOAD REDUCTION**

If a Customer has completed a test event, but not participated in actual events, their Committed Load Reduction will be based on nominated load. If a Customer has completed only one event, their Committed Load Reduction will be the higher of either their nominated load or their first event performance. If a Customer has participated in more than one event, their Committed Load Reduction will be based on an average of actual load reductions during event hours. The Customer, at its discretion, may choose to increase its nomination above the levels described above.

**QUALIFIED LOAD REDUCTION**

If no events are called in a Participation Month, the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for the full Reservation Payment during a month with events, the Customer must provide a minimum of 90% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month. If the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for a proportional reservation payment during a month with events, the Customer must deliver a minimum of 70% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month. If the Customer qualifies for a reduced reservation payment; the Qualified Load Reduction is the average load reduction for all event hours during that month.

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction for each and every hour during an event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Reduction Payment for that Event and the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer complies, the corresponding Energy Reduction Payments are paid for each event that the Customer delivers a minimum of 70% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month.

**RESERVATION PAYMENTS**

The Reservation Payment is the Customer's Qualified Load Reduction (per kW) multiplied by the sum of each applicable Reservation Price ($/kW) based on the Options selected by the Customer adjusted for losses based on the Customer's delivery voltage. For each event window (time period for an event) per season, only one price is applicable. The Reservation Payment is made to the Customer no later than 60 days after the month in which they participated.

SCHEDULE 26 (Continued)

**ENERGY PAYMENTS**

The Energy Payment is the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction Amount can be up to 120% of the commitment.

The monthly prices for energy per MWh are:

| Nov 2017 | Dec 2017 | Jan 2018 | Feb 2018 | Jun 2018 | Jul 2018 | Aug 2018 | Sep 2018 |
|---|---|---|---|---|---|---|---|
| $29.95 | $36.30 | $29.88 | $27.99 | $18.17 | $26.02 | $29.24 | $27.01 |

The Firm Energy Reduction Payment rates will be updated annually by December 1st for the next calendar year. Evaluation and settlement of the Firm Energy Reduction Payment will occur within 60 days of the Firm Load Reduction Event.

*Holidays are New Year's Day (January 1), President's Day (February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a holiday. If a holiday falls on Sunday, the following Monday is designated a holiday.

**LINE LOSSES**

Losses will be included by multiplying the applicable price by the following adjustment factors:

| | |
|---|---|
| Subtransmission Delivery Voltage | 1.0356 |
| Primary Delivery Voltage | 1.0496 |
| Secondary Delivery Voltage | 1.0685 |

**LOAD REDUCTION MEASUREMENT**

Load Reduction is measured as a reduction of Demand from a Customer Baseline Load calculation during each hour of the Load Reduction Event. Although the Firm Load Reduction Agreement shall specify the Customer Baseline Load calculation methodology to be used, PGE generally uses the following baseline methodology:

Baseline Demand Profile

The Baseline Load Profile is based upon the average hourly load of the three highest load days in the last ten Typical Operational Days for the Event period and an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Event. This adjustment is the difference between the Event day load and the average load of the three highest days used in the load profile above during the two-hour period four hours prior to the Event.



PROPOSED TARIFF DO NOT BILL

## SCHEDULE 26 (Continued)

LOAD REDUCTION MEASUREMENT (Continued)

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Firm Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the baseline calculation are defined as the ten applicable days closest to the Load Reduction Event. Typical Operational Days may exclude Saturdays, Sundays and WECC holidays.

The Company may decline the Customer's enrollment application when the Company determines the Customer's Energy usage is highly variable and the Company is not able to verify that a reduction will be made when called upon.

### FIRM ENERGY REDUCTION

The Firm Energy Reduction amount is the difference between the Customer's Baseline Energy profile and the Customer's measured hourly Energy usage during the Load Reduction Event.

### LOAD REDUCTION EVENT

The Company, at its discretion, initiates a Load Reduction Event by providing the participating Customer with the appropriate notification consistent with the Customer's selected Firm Load Reduction Option. The Customer reduces its Demand served by the Company, for each hour of the Load Reduction Event to achieve its Committed Load Reduction. Each load reduction event will last from one to five hours in duration.

The Company initiates Load Reduction Events during January, February, June, July, August, September, November, and December.

### EVENT NOTIFICATION

The Company notifies the participating Customer of a Load Reduction Event using a mutually agreed upon method at the time of enrollment. The Company's notification includes a time and date by which the Customer must reduce the committed Demand for each period of the Load Reduction Event.

The Customer is responsible to notify the Company if the Customer's contact information specified at the time of the enrollment changes as soon as such change occurs.

### FIRST-TIME PARTICIPANT

Optional Commissioning Test
A commissioning test is available to Customers who are participating on this schedule for the first time. Interested participants will work with the Company to learn the details of this process.



PROPOSED TARIFF DO NOT BILL

## SCHEDULE 26 (Continued)

### SPECIAL CONDITIONS

1. Customers cannot use on-site generation equipment for load reductions to meet load reduction commitments under this tariff.

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, or 590 will be withdrawn from this program.

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Reduction Event or the Customer's effort to reduce Energy in response to a Firm Load Reduction Event.

5. This tariff is not applicable when the Company requests or initiates Load Reduction affecting a Customer PODID under system emergency conditions described in Rule N or Rule C(2)(B).

6. The Company will not cancel or shorten the duration of a Firm Reduction Event once notification has been provided.

7. The Company will file any adjustment to the Reservation Rate by August 1st for the next program year.

8. Participating Customers are required to have interval metering and meter communication in place prior to initiation of service under this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage.

9. If the Customer experiences operational changes or a service disconnection that impairs the ability of the customer to provide the Firm Load Reduction as requested under this schedule, the agreement will be terminated.

10. If the Company is not allowed to recover any costs of this program by the Commission, the Company may at its option terminate service under this agreement with 30-day notice.

**SCHEDULE 26 (Continued)**

SPECIAL CONDITIONS (Continued)

11. The Customer may pre-schedule four opt-out days per season at nomination and indicated in the Agreement. If the Company calls a Load Reduction Event on a pre-scheduled opt-out day, the Customer is exempt from providing load reduction and receives no Firm Energy Reduction Payment, whether or not they choose to operate. The Customer will receive the Reservation payment if otherwise eligible. An opt-out day will not be included in the calculation of the Baseline Demand Profile.

12. Customers who opt for this Schedule may be placed on a calendar monthly billing cycle.

**TERM**

This pilot term is November 1, 2017 through September 30, 2020.



PROPOSED TARIFF DO NOT BILL

# PGE Advice No. 17-18
# Attachment A
# Cost Effectiveness Discussion

## Schedules 25 and 26 Nonresidential Demand Response Cost Effectiveness

The analysis estimates the cost effectiveness of three commercial Demand Response (DR) programs that will replace PGE's Energy Partner program in fall 2017. Current program enrollment assumptions, cost, and benefit estimates indicate a positive preliminary benefit: cost ratio of 1.03 for the Total Resource Cost Test. This is the primary metric used by the OPUC.[1]

**Total Resource Cost Test**

| Cost/Benefit Category | Costs | Benefit |
|---|---|---|
| Administrative costs | $6,600,000 | |
| Avoided costs of supplying electricity | | $20,460,000 |
| Bill Reductions | | |
| Equipment costs to utility | $4,810,000 | |
| Environmental benefits | | $20,000 |
| Incentives paid | | |
| Revenue loss from reduced sales | | |
| Transaction costs to participant (25%) | $4,190,000 | |
| Value of service lost (25%) | $4,190,000 | |
| | $19,790,000 | $20,480,000 |
| **Benefit Cost Ratio** | | **1.03** |

Costs and benefits reported in the above table are the net present value of a 20-year stream of revenue and expenses.[2] Three additional tests are included on the final page of this report.

The general approach employed in this analysis is to align with recent PGE analyses of DR programs. PGE expects that upcoming dockets with the Oregon Public Utility Commission and stakeholders will refine the methodological approach to calculating program cost effectiveness, and analyses of future programs (as well as post-pilot analyses of existing programs) may look different and thus conclude different results.

### Key Programmatic Assumptions

- This analysis encompasses three commercial DR program structures, all of which will be implemented by the same vendor team and through a single contract:
    1. Small Business (Schedule 25). Incentives consist of a free thermostat and $60 annual payment. Events are limited to 80 hours per year; five hours per event. The hours in which events may be called are delineated in the tariff. Event notification is provided four hours in advance.

[1] The application of this test to the Commercial and Industrial Demand Response program follow the methodology proposed in Navigant's 2016 memo, *A Proposed Cost-Effectiveness Approach for Demand Response*.
[2] Annual costs and benefits were discounted using the weighted average cost of capital of 7.18% (September 2017 update).

2. Standard (Schedule 26). Participants receive capacity and energy payments per kW nominated for curtailment and kWh reduced during events. Events are limited to 80 hours per year; five hours per event. The hours in which events may be called are delineated in the tariff. Event notification is provided four hours in advance.
3. Custom (Schedule 26). Participants select the hours in which they will participate, the notification timeframe, and maximum hours per year. Capacity incentive per kW nominated is adjusted accordingly. Energy payments reflect actual kWh curtailed during events.

Cost benefit modeling averages incentives across program types and anticipated participation levels.

- Program participation increases over three years to achieve PGE's goal of 27 MW by 2020 (AAGR of 40%).
- In years 6-20, the program is modeled to grow more slowly at 3% annually, achieving 42 MW of demand reduction by 2036. This is a conservative growth estimate; vendor contracts are for five years only. This cost estimation approach accounts for program expansion and maintenance as well as equipment replacement as (5-10 year) asset life is exceeded.

## Goals of Pilot Project

- Grow all DR programs into sustainable, long-term programs incorporated into the PGE dispatchable resource stack.
- Future program evaluation anticipates repeating these tests and replacing assumptions with both observed results and any program adjustments that may occur due to participant feedback. These inputs may include:
  - Customer adoption rates and distribution across program options.
  - Allocation of payment across variable (energy) and fixed (capacity) components.
  - Updated vendor costs (program administration and equipment).
  - Realization of participant kW nominated for curtailment.

## Cost Details

- **Administrative and Equipment Costs**. Vendors CLEAResult and Enbala are under contract as third party implementers of these programs. Administrative and equipment costs reflect all labor and expenses. All costs are to be expensed; no equipment will be capitalized. The Enbala contract will support multiple programs; costs were assigned to this program as total proposed cost minus costs previously negotiated for the Water Heater pilot.
- **Transaction Costs to Participants**. Transaction costs reflect the inconvenience/intrusion associated with the installation process, program education, and program audit and evaluation. Costs are considered indirect, and defined as a percentage of the incentive provided. C&I DR modeling currently assumes 25% or low transaction costs, consistent with Navigant's 2016 review of the Energy Partner program. This percentage was assigned to total estimated annual incentives paid.

- **Value of Lost Service**. Loss of service costs are intended to reflect productivity and comfort losses, and are also calculated as a percentage of the incentive payment. The model assumes the service loss equates of 25% of the incentive payment, consistent with Navigant's 2016 review of the Energy Partner program.

## Benefit Details

- **Avoided Cost of Supplying Electricity**. Typically three value streams are included.
  1. Avoided Cost of Capacity. Demand response reduces PGE's need for capacity by reducing demand. To estimate the value (or cost) of the capacity avoided, this analysis multiplies the average net reduction in demand (kW) per participant x the number of participants x the value of one kW of additional capacity. The value of capacity is based on the real levelized fixed cost of a simple cycle combustion turbine (1x0 GE 7F.05). PGE's 2016 IRP found this to be the least cost dispatchable unit at an estimated $125.70/kW-year (2018 dollars). Total fixed cost includes capital ($58.19), fixed O&M wheeling ($29.46), and fixed gas transport ($38.04). This value is then grossed up for line losses (6.85% per PGE secondary delivery voltage adjustment factor + 2.06% to reflect marginal peak vs. average line loss).
     - Discount Factors. The Avoided Cost of Capacity is then discounted to reflect the operational differences between a dispatchable thermal resource and demand response (as described by this program's parameters).
       The most influential discount factor employed in the analysis is the A factor. Navigant describes the A factor as the percent of overlap between program availability hours and forecasted periods of highest demand or load loss. The most accurate approach for determining this factor would be to run PGE's loss of load probability model (RECAP) with the DR program parameters. Both time constraints and the maturity of the model inhibited this approach. As an alternative, A factors used in similar D&R programs elsewhere were reviewed, and applied from the program with most similar parameters. Because this program offers a broad range of participation options, a blend of A factors was employed:
       - Southern California Edison's Commercial Base Summer Discount Plan is limited to 90 annual event hours with six hour event duration (A factor 44.8%). This was applied to the Small Business, Standard, and 45% of Custom participants (on the assumption that 45% of Custom participants select a cap of 80 hours annually).
       - Southern California Edison's CPP is limited to 12 events per year, 48 hours per month, with four hour event duration (A factor 26.1%). This was applied to 10% of Custom participants (on the assumption they select a cap of 40 hours annually).
       - Southern California Edison's Residential Summer Discount Plan is limited to 180 hours per year with six hour event duration (A factor 65.7%). This was applied to 45% of Custom participants (on the assumption they select a cap of 160 hours annually).

The resulting blended A factor, applied across the three program offerings, is 47%. This is a more conservative assignment than was employed for the Energy Partner program, which this C&I program replaces. Navigant reviewed that program and found that its parameters were most similar to PG&E's PeakChoice program (maximum 75 hours), for which the A factor was widely estimated at between 41% and 82%, depending on the assumptions around historical load hours. Given the broad range, Navigant assumed a mid A factor value of 60% for the Energy Partner program.

Discount factors were applied as follows:

| | |
|---|---|
| A Availability | 47% |
| B Notification | 95% |
| C Trigger | 100% |
| D Distribution – adder | 0% |
| Total de-rate: | 45% |

Notification is modeled as 95%, also a blend across programs of the 4-hour notification time frame (94%), 18 hour notification time frame (88%), and 10 minute notification timeframe (100%). The Small Business and Standard programs both require a four hour notification; Custom participants can select their notification timeframe.

No discount was applied for trigger, because the tariff will not identify required conditions (or triggers) for an event to be called. No distribution adder was modeled, as the program does not allow for distribution investment deferrals.

The end result is an Avoided Cost of Capacity of $60.18 per kW in 2017. See the end of this memo for a table detailing the blending of A and B factors across program types, and the calculation of incentive per kW hour for each program and participation selection.

2. Avoided Cost of Distribution. This program claims no locational benefits that would defer additional investment in transmission or distribution infrastructure. It is also not expected to adjust a participant's kW of monthly on peak demand, the basis of transmission and distribution charges for large nonresidential customers (Schedule 85), given a limited number of calls per season. Therefore no avoided cost of transmission and distribution benefits was assigned.
3. Avoided Cost of Electricity is the final component of the Avoided Cost of Supplying Electricity. This was calculated by multiplying the target MW capacity reduction per year x estimated average event duration (three hours) x estimated number of annual events (15) x estimated net change in energy usage times x energy cost (on-peak Aurora pricing, consistent with 2016 IRP, without $CO_2$). Snapback – or the extent to which energy is shifted, rather than reduced – is estimated at 90%, meaning the net energy change would be fairly minimal at

10%. The total Avoided Cost of Electricity comprises less than 1% of the Avoided Cost of Supplying Electricity.

- **Environmental Benefits**. This is defined as the CO2 tax that is avoided when decreased demand results in decreased energy usage. In accordance with PGE's 2016 IRP, CO2 tax is expected to be realized in 2022; only energy reductions in that date or later receive this benefit. This benefit comprises less than 1% of the total benefit in the Total Resource Cost Test.

**Program Assumptions**

| | Participants | MW | Avg Nomination (kW) | E savings (kW) | Customer Share | Capacity Payment Capacity $ per kW | Avg Annual per participant | A Factor | Southern California Edison DR Program - basis of A factor selection* | B factor* |
|---|---|---|---|---|---|---|---|---|---|---|
| **Small** | 89 | 4 | 45 | 1,808 | 100% | 1.33 | 60 | 44.8% | SDP Non-Res Base program. 90 hours/year, 6 hour/day | 94% |
| **Standard** | 167 | 15 | 90 | 3,615 | 100% | 52.52 | 4,727 | 44.8% | SDP Non-Res Base program. 90 hours/year, 6 hour/day | 94% |
| **Custom** | | | | | | | | 0.0% | | |
| *20 hours* | *1.30* | *0.8* | | | *10%* | *40.12* | | 26.1% | CPP. 12 events per year, max of 48 hours per month, 4 hours/day | 88% |
| *40 hours* | *5.85* | *3.6* | | | *45%* | *60.18* | | 44.8% | SDP Non-Res Base program. 90 hours/year, 6 hour/day | 94% |
| *80 hours* | *5.85* | *3.6* | | | *45%* | *80.05* | | 65.7% | SDP Res. 180 hours/year, 6 hours/day | 100% |
| Custom average | 13 | 8 | 600 | 24,102 | 100% | 67.12 | 40,270 | 0.0% | | |
| | 269 | 27 | 735 | 29,525 | | 49.26 | 4,903 | 47.0% | *Demand Response Measurement and Evaluation, Program Enrollment and Load Impacts, Cost-Effectiveness, and Ratemaking Proposal Soutern California Edison , March 1, 2011 | 94.6% |

"100%" participation value

*B factor driven by varying notification periods per PGE program options

**Total Resource Cost Test**

| Cost/Benefit Category | Costs | Benefit |
|---|---|---|
| Administrative costs | $6,600,000 | |
| Avoided costs of supplying electricity | | $20,460,000 |
| Bill Reductions | | |
| Equipment costs to utility | $4,810,000 | |
| Environmental benefits | | $20,000 |
| Incentives paid | | |
| Revenue loss from reduced sales | | |
| Transaction costs to participant (25%) | $4,190,000 | |
| Value of service lost (25%) | $4,190,000 | |
| | $19,790,000 | $20,480,000 |

**Benefit Cost Ratio** **1.03**

**Program Administrator Cost Test**

| Cost/Benefit Category | Cost | Benefit |
|---|---|---|
| Administrative costs | $6,600,000 | |
| Avoided costs of supplying electricity | | $20,460,000 |
| Bill Reductions | | |
| Equipment costs to utility | $4,810,000 | |
| Environmental benefits | | |
| Incentives paid | $17,820,000 | |
| Revenue loss from reduced sales | | |
| Transaction costs to participant | | |
| Value of service lost | | |
| | $29,230,000 | $20,460,000 |

**0.70**

**Rate Impact Measure Test**

| Cost/Benefit Category | Cost | Benefit |
|---|---|---|
| Administrative costs | $6,600,000 | |
| Avoided costs of supplying electricity | | $20,460,000 |
| Bill Reductions | | |
| Equipment costs to utility | $4,810,000 | |
| Environmental benefits | | |
| Incentives paid | $17,820,000 | |
| Revenue loss from reduced sales | $100,000 | |
| Transaction costs to participant | | |
| Value of service lost | | |
| | $29,330,000 | $20,460,000 |

**0.70**

**Participant Cost Test**

| Cost/Benefit Category | Costs | Benefit |
|---|---|---|
| Administrative costs | | |
| Avoided costs of supplying electricity | | |
| Bill Reductions | | $100,000 |
| Equipment costs to utility | | |
| Environmental benefits | | |
| Incentives paid | | $17,820,000 |
| Revenue loss from reduced sales | | |
| Transaction costs to participant | $4,190,000 | |
| Value of service lost | $4,190,000 | |
| | $8,380,000 | $17,920,000 |

**2.14**

# PGE Advice No. 17-18
# Attachment B
# Commercial & Industrial Demand Response Program Redesign from Navigant

NAVIGANT

# Commercial & Industrial Demand Response Program Redesign

**Presented to:**

**Portland General Electric**

*Portland General Electric*

*121 SW Salmon St,*

*Portland, OR 97204*

*March 23 2017*

**Presented by:**

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# Table of Contents

## Executive Summary

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[1] with a significant portion coming from the commercial and industrial (C&I) sectors. However, PGE has faced challenges building C&I DR capacity through its existing C&I DR portfolio, consisting of the Energy Partner program and Schedule 77. This study identifies recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

### Findings

Since the program's inception in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. PGE's service area is a difficult one to develop an effective C&I DR resource, due to a variety of factors including limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. Compounding this difficult business environment, the program's aim to deliver a firm and valuable resource to the Company has resulted in relatively strict rules for participation and performance that have limited enrollment and the number of MW that customers are willing and able to contribute.

The following are specific findings relating to 1) the PGE customer base and operating environment, 2) the Energy Partner program structure, and 3) the program delivery.

**PGE Customer Base and Operating Environment:**

1. PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.
2. PGE is losing potential large C&I demand response opportunities due to large customers choosing alternative providers.
3. Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation.
4. PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.

**Program Structure:**

1. Current participants are satisfied with most aspects of the program.
2. Having dual peaks creates unique and significant challenges for implementing demand response.
3. The duration of the event windows presents a challenge for the program implementer and some customers.
4. PGE's peak hours are not necessarily coincident with C&I customer peak hours.
5. The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.
6. The 10-minute notification time is not a significant barrier for customers in practice.
7. Enabling more customers with automated curtailment would increase the curtailment

[1] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.

available from both non-participants and participants alike, although at a higher program cost.

**Program Delivery:**

1. Corporate social responsibility and "doing the right thing" is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.
2. The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.
3. Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.
4. Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.
5. Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.
6. Opportunities exist for impactful coordination with the Energy Trust of Oregon's Strategic Energy Management (SEM), but require strategic effort from PGE.
7. KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.

## Recommendations

The recommended changes in the design of PGE's C&I DR program offerings reflect changes in PGE's priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

The following are specific findings relating to 1) the target market, 2) the proposed program structure, and 3) the program delivery.

**Target Market:**

PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. Non-industrial/process loads at large C&I customers, such as lighting and HVAC
2. Medium-size C&I customers (200 kW to 1+ MW peak load)
3. Small-size C&I customers (<200 kW peak load)
4. Site aggregation
5. Direct access customers

**Program Structure:**

1. Allow more flexibility across seasons and within seasons.
2. Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.
3. Facilitate partial credit for partial participation.
4. Relax the notification time requirement for participation.
5. Emphasize automated curtailment, where possible, but continue to support both manual and

automated curtailment.

6. Revisit the methodology used for determining a customer's baseline to avoid penalizing customers with variable load.

**Program Delivery:**

1. Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.
2. Focus the program marketing and delivery around the benefits to the customers.
3. Enhance education for both participants and non-participants.
4. Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust's day-to-day processes with minimal overhead.
5. Increase marketing to medium-size customers (200 kW to 1+ MW peak load).
6. Evaluate options for using existing interval meters to lower program equipment costs.
7. To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.
8. Leverage existing and new channels for broader and more continuous customer engagement.

# Section I Introduction

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[2] with a significant portion coming from the commercial and industrial (C&I) sectors. PGE's C&I DR portfolio currently consists of the Energy Partner program with 10-15 megawatts (MW)[3] and Schedule 77 with 1.8 MW. Since the inception of the Energy Partner program in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. Given the challenges that PGE has encountered with achieving target DR capacity from the C&I sectors, the objectives of this study are to identify recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

To support the findings in this study, Navigant conducted interviews with the following stakeholders:

- PGE program staff
- Energy Partner program manager at the program implementer (EnerNOC)
- Strategic Energy Management (SEM) program manager at the Energy Trust of Oregon (Energy Trust)
- 10 participants
- 10 non-participants, including 5 customers currently participating in the SEM program, 4 customers who had previously declined to participate in the program, and 1 former participant
- This study is organized into the following sections: **Section II: Findings** presents the findings from the interviews noted above, as well as Navigant's review of relevant secondary

[2] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.

[3] EnerNOC's expected nominations for the Energy Partner program are 13.5 MW for Winter 2016/2017 and 11.3 for Summer 2017.

resources from PGE and other jurisdictions, including benchmarking results comparing PGE's C&I customer base with other utilities around the country.

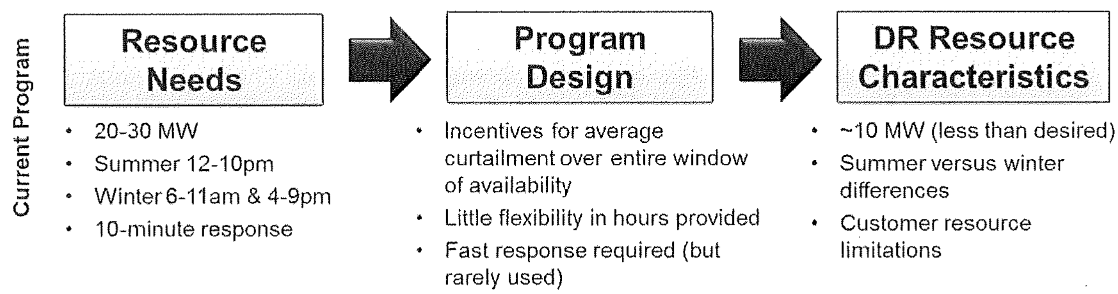
- **Section III: Recommendations** discusses recommendations for refining PGE's C&I DR program offerings, based on the findings in Section II and best practice programs at other utilities, as well as recommendations for conducting the procurement process.
- **Section IV: Summary** provides a summary overview of the issues and recommendations.

# Section II Findings

PGE initially designed the Energy Partner and Schedule 77 programs to maximize the value of the resource to PGE's system, with fast response time and comprehensive windows of availability, as shown in Figure 1. For the reasons discussed in this section, these objectives are difficult to achieve in a robust, cost-effective program within PGE's service area.

A key theme expressed by both PGE and customers was the desire for more flexibility within the program design and eligibility requirements to facilitate broader customer participation and increased customer satisfaction. In other words, moving from a "one size fits all" program to one with more options for when and how customers participate.

**Figure 1. Philosophy of Program Design: Current Program**




*Source: Navigant, 2017.*

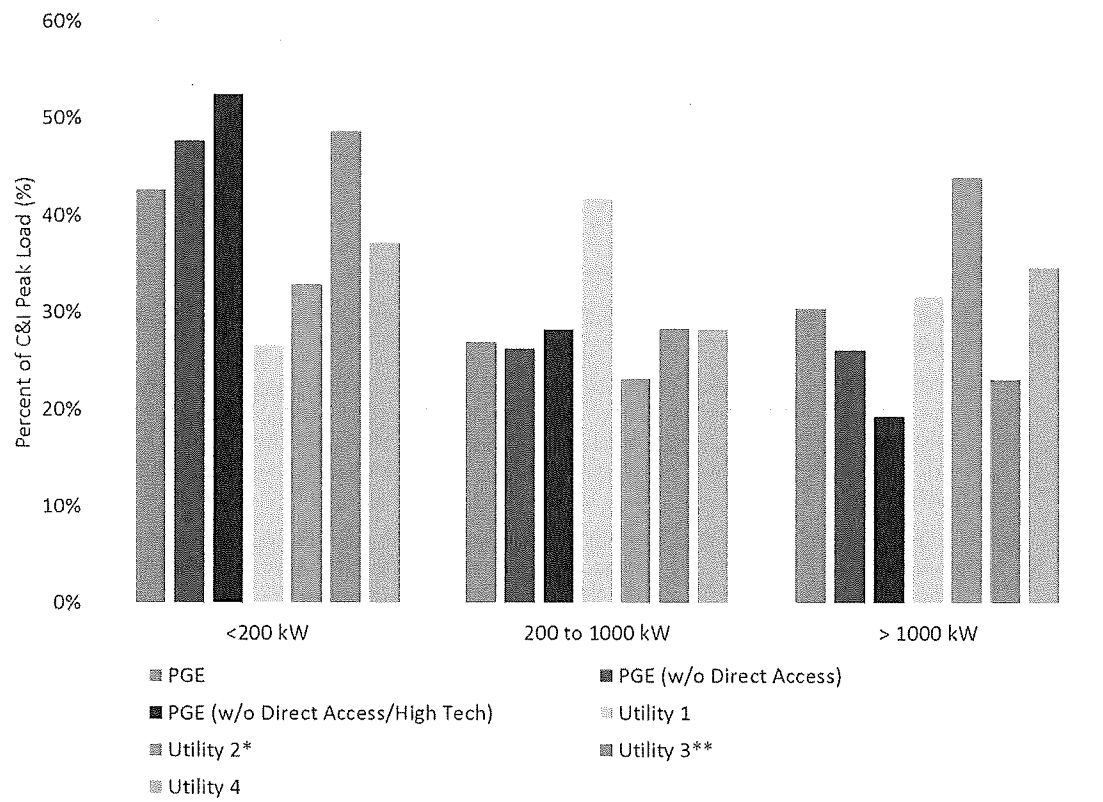
## 2.1 PGE Customer Base and Operating Environment

The following section discusses the finding relating to the market characteristics and system requirements within which the Energy Partner program operates.

1. **PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.** Other utility programs around the country often rely on just a few very large customers to provide the bulk of curtailment. For example, Xcel Energy Colorado currently has roughly 200 MW out of the 300 MW available from their C&I program through just two customers. Similarly, Oncor's early-stage C&I DR program had 9 MW of 11 MW from a single customer. Compared to these other regions, PGE's customer base has fewer large industrial customers who can shift or shed load during PGE's peak times. For example, one-third of PGE's demand from customers with greater than 1 MW peak load is from high-tech manufacturing customers. These customers have significant load and would be prime candidates for participation; however, they are generally reluctant to participate due to the limited options available for participation without impacting production, the high consequences of production disruption, and the relatively limited benefits of participation in comparison to these factors. Similar barriers exist for hospitals. Navigant has seen these challenges with enrolling high-tech manufacturing and hospitals in other service areas, as well.

Figure 2 shows the percent of PGE's C&I customers by size compared to other utilities with C&I DR programs. After factoring out high-tech manufacturing and direct access (discussed in below) customers who are unable to participate, PGE has a significantly smaller proportion of large C&I customers than other utilities.

**Figure 2. Benchmarking Comparison of PGE C&I Peak Load to Other Utilities by Size**




*Source: Navigant, 2017 and utility data.*

** Utility 2 based on Average Monthly Load data and size breakdowns of <500kW, 500-1000 kW and >1000 kW*

*** Utility 3 based on size breakdowns of <300 kW, 300-1000 kW and >1000 kW*

2. **C&I load is declining due to large customers choosing alternative providers**. As an example, two customers recently left the program when their companies switched to direct access and were no longer eligible for the program. Based on their experience in other jurisdictions, EnerNOC contends that these customers and potentially other national chains would return to the program if direct access customers were eligible; however, PGE would need to work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers. Figure 2 indicates the magnitude of impact from excluding direct access customers.

3. **Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation**. EnerNOC does not currently permit aggregation of metered locations on a customer site below a certain size threshold, due to the cost of installing the separate meters that EnerNOC requires for participation at each metered location on the customer site. This presents a significant barrier for the participation of certain customers, such as campus-like customers with multiple smaller facilities on a single site.

4. **PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.** Within PJM's entire DR portfolio, generators alone comprise 12 percent of nominated capacity.[4] As another example, within Duke Energy Progress's C&I Demand Response Automation Program, generators comprise more than 75 percent of their summer DR impacts and more than 90 percent of their winter DR impacts.[5] PGE recently changed the program rules, such that the Energy Partner program may be marketed to customers who also participate in PGE's DSG program. However, the customer is only permitted to participate in Energy Partner with load, rather than the generators. EnerNOC estimated that the additional curtailment that could be achieved if EPA compliant generators were eligible is between 3 and 4.5 MW. While PGE does not plan to permit the use of generators for DR, it is worth noting that the exclusion of this resource limits available MW, relative to other DR programs. The limitation of generation also impacts participation from segments with sensitive loads like hospitals and high-tech customers, who are reticent to curtail end use loads.

## 2.2 Program Structure

The following section discusses findings related to the structure of PGE's existing Energy Partner program, including program parameters like event timing and duration.

1. **Current participants are satisfied with most aspects of the program.** Participants responded with an average of 8.4 when asked how satisfied they are with the Energy Partner, where a 0 meant they are extremely dissatisfied and a 10 meant they are extremely satisfied. Customers also expressed general satisfaction in their interactions with EnerNOC, PGE, and their KCM.
2. **Having dual peaks creates unique and significant challenges for implementing demand response.** PGE's demand response targets are similar in the winter and the summer through at least 2021. Thus, PGE's current program requires customers to enroll for both winter and summer. While customers are able to nominate different load amounts in each season, it is hard for some customers to offer curtailment in both summer and winter. As an example, three of the four prospective non-participants interviewed mentioned that participation would be significantly harder for them in the winter than in the summer.

   Implementers must enroll customers who are able to curtail in both seasons or incur additional costs enrolling customers who can only participate in one season. Although program delivery costs increase by as much as 40 percent when providing curtailment in both summer and winter, PGE's avoided costs are split across seasons, which means that an implementer must be able to provide almost double the curtailment for half of the avoided cost value.
3. **The duration of the event windows presents a challenge for the program implementer and some customers.**[6] The duration of the event window is much larger than in most other programs (i.e., typically two to four hours), although the vast majority of PGE's events over the past several years have occurred in the 4-7 p.m. timeframe. The broad event windows limit the pool of candidates who are available to curtail across all possible event hours and incurs additional costs on the part of the program implementer to identify those candidates or bear the risk that less-suitable companies will not be able to provide sufficient demand reduction if events are called outside of the 4-7 p.m. timeframe.
4. **PGE's peak hours are not necessarily coincident with C&I customer peak hours.** PGE's

[4] http://pjm.com/~/media/markets-ops/dsr/2016-demand-response-activity-report.ashx
[5] Navigant analysis, Duke Energy Progress Commercial, Industrial and Governmental Demand Response Automation Program, Program Year 2015.
[6] During the summer and winter periods, program events may be called: 1) during non-holiday weekdays from 12 p.m. to 10 p.m. Pacific Time for the summer period; and 2) during non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. Pacific Time for the winter period.

peak occurs later in the day than for many utilities with large C&I DR programs. The 4-7 p.m. timeframe works well for some C&I customers that are changing shifts during this time or have fewer customer occupancy concerns outside of their core business hours. However, it also limits participation from customers, particularly commercial, who operate primarily 9 a.m. to 5 p.m. and either have limited load available to curtail or would need to pay someone overtime to manage the event curtailment. As discussed in the recommendations below, some customers thought that automated curtailment could help minimize this barrier.

None of the participants expressed concerns about participating in morning events, which is likely due to the fact that PGE has only called one morning event in the history of the program. However, the requirement that customers must be available to participate in both the morning and evening means that the program heavily favors 24/7 customers and can present a perceived barrier for non-participants.

5. **The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.** Requiring the ability to curtail within ten minutes limits the pool of customers eligible for the program and increases program delivery costs through increased automation needs, added risk absorbed by the implementer, and more limited enrollment options. Several non-participants said that they would need at least an hour to curtail load, particularly without automation.
6. **The 10-minute notification time is not a significant barrier for customers in practice.** In practice, EnerNOC generally provides customers with an alert that an event may be coming, then gives customers at least three hours of advance notice. EnerNOC tells customers to expect two to four hour notice, but they may need to perform in ten minutes in rare circumstances. Current participants generally seem satisfied with this arrangement.
7. **Enabling more customers with automated curtailment would increase the curtailment available from both non-participants and participants alike, although at a higher program cost.** Manual curtailment with 10-minute notification is challenging for many customers, who are shutting down multiple loads, and a perceived barrier for non-participants. Furthermore, the late afternoon and evening timing for PGE's events means that many C&I customers need to pay someone overtime to manually curtail load during events. With automation, these customers could potentially still participate after the main business hours.

   Half of the non-participants interviewed said that automation would increase the chances of their participation. PGE also recently worked with a customer interested in participating in Energy Partner who ultimately decided not to participate because they wanted automation and were not able to make it pencil out with PGE and the Energy Trust.

## 2.3 Program Delivery

The following section discusses the findings related to the program delivery, including marketing and outreach strategies, as well as contracting considerations.

1. **Corporate social responsibility and "doing the right thing" is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.** Only two of the ten participants interviewed responded that financial benefit is their primary driver for participation. Thus, the financial incentive is an important factor, but is not the only factor driving customers to participate, and often it is not sufficient to serve as the sole benefit to customers.
2. **The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.** Non-participants also expressed concern with the costs of enablement, occupant comfort, and staff time during events. For example, the Energy Trust of Oregon cited that their SEM customers historically do not see enough upside benefit from the program for them to spend time setting up DR at their site. This fits with EnerNOC's findings that reasons provided by customers who are "not interested" in the program included: *too much work*, *too disruptive*, *does not see how it fits into operations*, and *not worth it*. It should

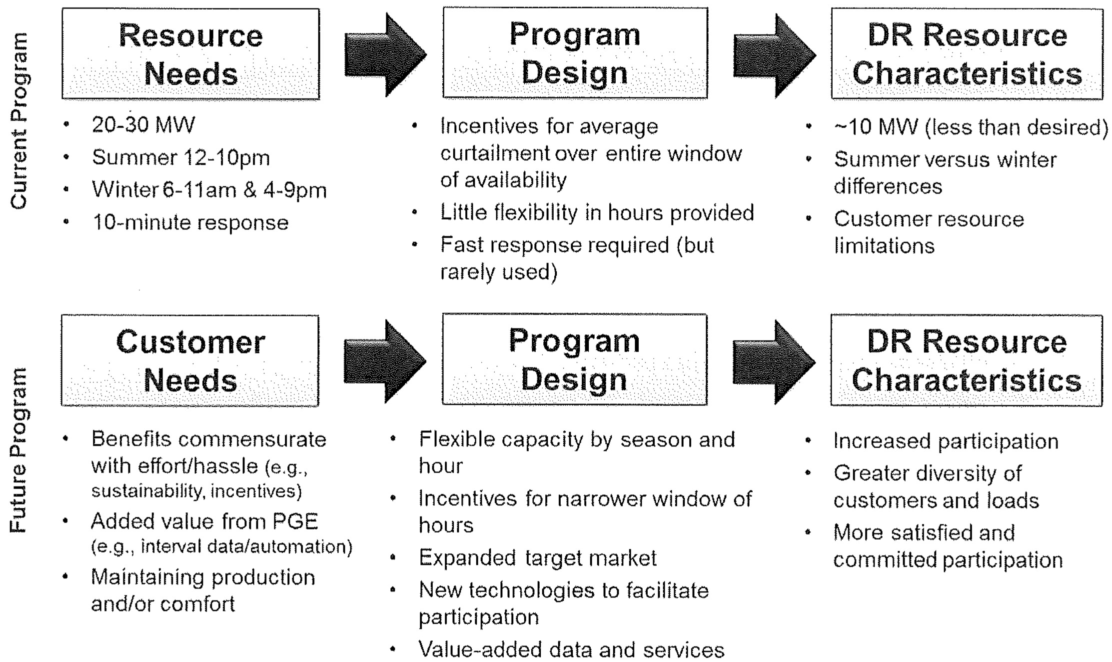
be noted that some customers are unlikely to participate, regardless of the financial value proposition that the program offers, such as customers with sensitive 24/7 operations.

3. **Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.** Both participants and non-participants alike expressed interest in having more resources available to help them and their stakeholders (i.e., customers, staff, and internal management) understand a range of topics, including how the program works; the value of the program to their organization and society; the potential drawbacks and costs of participating; and how to optimize their curtailment strategy. This lack of education might also be a key driver for the customer perceptions discussed in #2 above.
4. **Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.** Half of the participants interviewed reported revising their initial curtailment strategy to lower targets and some reported still having issues meeting their targets. Part of these changes resulted from changes in the customer's operation, while part of these changes resulted from customers learning more about DR and how it affects their facility. For example, one customer had been initially unaware of how their curtailment strategy would be impacted in the winter versus the summer.
5. **Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.** EnerNOC currently requires that customers install a separate meter for participation, even if customers already have an interval meter. This separate meter provides customers with near-real-time energy information, as opposed to the next-day information that PGE's existing interval meters would provide. During interviews, only three of the ten participants mentioned using the system in real-time during events. The other comments from participants suggest that a system providing next-day information would largely suit customers' needs.
6. **Opportunities exist for impactful coordination with the Energy Trust of Oregon's Strategic Energy Management (SEM), but require strategic effort from PGE.** Energy Trust of Oregon and PGE concur that the SEM program is a good channel for informing C&I customers about DR, given that SEM participants tend to have high acceptance and awareness of energy-related opportunities. One Energy Partner participant even said that the change in their organization's culture and thinking about energy use through the SEM program paved the way for them to enroll in Energy Partner. However, successful collaboration with the SEM program will need to overcome barriers relating to limited staff time, customer and contractor education, customer fatigue, and technical integration. Recommendations for overcoming each of these are discussed in Section 3.3 below.
7. **KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.** KCMs currently manage about half of the current participants, with the other half unmanaged. EnerNOC leads the enrollment process, with a hand-off mechanism between the KCMs and EnerNOC. With training, clearly defined expectations, and aligned incentives, KCMs could likely play an enhanced role in engaging customers in the program.

# Section III Recommendations

The section below discusses recommended changes in the design of PGE's C&I DR program offerings to reflect changes in PGE's priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

**Figure 3. Philosophy of Program Design: Future Program**




*Source: Navigant, 2017.*

## 3.1 Target Market

Historically, the target market for the Energy Partner program has been larger C&I customers, particularly in the industrial sector. Expanding the targeted reach of the program to additional market segments can contribute to significant incremental DR capacity if certain barriers are removed. PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. **Non-industrial/process loads at large C&I customers, such as lighting and HVAC:** Enabling additional types of load at the customer site could increase nominations from existing participants and entice participation from customers with sensitive processes that might not otherwise participate. For example, three of the ten participants interviewed responded that they could potentially curtail more load at their facility by expanding their curtailment strategy beyond process equipment to other loads like lighting, particularly with automation or assistance upgrading equipment. Hospitals and high-tech customers, who are otherwise unwilling or unable to participate by curtailing process-related loads, may consider curtailing non-essential HVAC and lighting in office spaces with the appropriate value proposition for doing so.
2. **Medium-size C&I customers (200 kW to 1+ MW peak load):** PGE has roughly the same amount of load from medium-size C&I customers as from larger customers with 1+ MW (see Figure 2). New strategies are emerging for engaging these customers in DR, as vendors and utilities around the country are looking beyond large C&I customers. These implementation strategies include distributed, networked, high-tech, relatively low-cost communication and control technologies that can communicate back to a central control center. One example of a vendor that participates in this market is Encycle. Smart thermostats might also be used as a value-add to the customer, as well as for enabling communications and control. While the "jury is still out" to some degree on the cost-effectiveness and efficacy of these new strategies, PGE should evaluate options for engaging with this segment during the

procurement process.

3. **Small-size C&I customers (<200 kW peak load):** More than 40 percent of PGE's C&I load comes from C&I customers with less than 200 kW peak load (see Figure 2). While this segment has traditionally been challenging for C&I DR programs, it is worth exploring with vendors during the procurement process to understand options available for that segment. Expanding into this segment would require allowing customer nominations of less than 75 kW and may warrant a separate program or tariff structure. Vendors may approach this segment as an extension of the medium-size C&I market, with distributed low-cost communications and control technologies to 50-200 kW customers, or as a mass market program, which could be an extension of PGE's Nest thermostat program to small commercial.
4. **Site aggregation:** Use of existing interval meters and allowing the aggregation of multiple meters would enable more customers to participate and lower program equipment costs. In EnerNOC's view, site aggregation "is what is needed for PGE's program, if [PGE] could get it cost effectively." The ability to facilitate site aggregation will largely be dependent on the vendor's capabilities and requirements.
5. **Direct access customers:** Work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers for participation in a C&I DR program.

## 3.2 Program Structure

The following section discusses recommendations for reframing the structure of PGE's C&I DR program, including program parameters like event timing and duration.

1. **Allow more flexibility across seasons and within seasons.** To maximize customer eligibility, PGE should allow differences in nominations within seasons and allow customers to participate in only one season.[7]
2. **Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.** DR programs often fail when they try to cast too wide of a net. PGE should prioritize the top two to four most important hours needed for generation capacity deferral in each season as the required hours that a customer must be available to be eligible for the program. Enrollment for any hours outside of this window could be optional, based on the customer's operational needs. PGE could facilitate this by breaking the existing event windows up into more discrete windows (e.g., winter morning, winter evening, etc.) and providing a different value for each window. ERCOT's programs function similarly to this, with three seasonal program periods and multiple daily windows within each season that can be bid into separately —with a different price for each period.
3. **Facilitate partial credit for partial participation.** Under the current program structure, customers who can curtail for only a portion of the event window do not get payment, which discourages customers from participating in the event at all. PGE should explore ways to provide compensation to customers for partial participation, such as providing a reduced incentive of allowing customers to participate for just one hour at a time.
4. **Relax the notification time requirement for participation.** Given that PGE's primary objective for the C&I DR resource (i.e., generation capacity deferral) does not require 10 minute notification, Navigant recommends that PGE change the program requirements to a more traditional 2 or 4 hour notification. While EnerNOC currently operates the Energy Partner program with 2-4 hour notification in practice, lifting this requirement will help decrease program delivery costs by broadening the pool of eligible customers, decreasing automation needs, and reducing the amount of risk absorbed by the implementer.
5. **Emphasize automated curtailment, where possible, but continue to support both manual and automated curtailment.** Allowing both manual and automated curtailment reaches the broadest mix of customers, since some customers (e.g., with sensitive production

[7] Currently, differences in nominations are allowed across seasons, but not within seasons.

loads) will always prefer manual participation. However, facilitating automation for more customers (e.g., through financing, technology incentives for enablement, etc.) can help firm the resource and also allow certain customer segments to participate by curtailing remotely, as opposed to paying employees overtime to curtail after business hours. As an example, three of the seven non-participants with manual curtailment and four non-participants expressed possible interest in financing options from PGE for upgrading or installing a building management system (BMS) to enable automated curtailment.

6. **Revisit the baseline methodology used for some customers to avoid under- or over-estimating the baseline demand of customers with highly variable load.** PGE's current baseline method takes the highest 5 of 10 prior business days, with day-of adjustment except for winter mornings. For some customers with load that is highly variable (apart from weather-related variability), this can lead to a disconnect between demand reduction estimates and the actual DR actions. As an example, a customer with a large irregular industrial process load that was operating on the 5 highest of the 10 past business days, but not on the day of the DR event, would have a baseline that vastly over-estimates their true baseline demand the day of the event. This scenario can lead to challenges with program impact evaluation, less predictable program performance, and decreased participant satisfaction in the program outcomes. To account for this while still allowing customers with highly variable load to participate in a meaningful, more predictable way, PGE may consider offering certain customers one of the following options:
   a. Allow a customized baseline for customers with additional operational information that can help design a baseline methodology tailored to their specific operating characteristics. This is consistent with the evaluation findings of the Energy Partner program that a regression baseline could perform better for some customers.
   b. Allow certain participants to provide their own day-ahead baseline every day before the standard notification time, with penalties for large departures from the participant's "scheduled" load on non-event days.
   c. Require that these participants achieve a firm service level, rather than curtailing a certain amount (i.e., a "down-to" commitment as opposed to a "down by" commitment). PGE could do this through the existing Schedule 77 tariff or by providing a customer with a choice of baseline via the Energy Partner program. However, this approach provides PGE with less visibility into the probability that the load will be available for curtailment than the other options discussed above.[8]

## 3.3 Program Delivery

The following section discusses recommendations for changes to the program related to the program delivery, including marketing and outreach strategies.

1. **Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.** Table 1 below shows recommended roles and responsibilities for the implementation vendor and PGE's existing DRMS vendor, relative to PGE. The agreement with the implementation vendor should consider the following:
   a. **Overall structure:** If PGE wants to manage the marketing and recruitment but needs more help on the technical side and back-end support, it can find the right type of vendor to provide such functions. More than likely, PGE should explore arrangements outside of a pay-for-performance structure to facilitate more program flexibility and

[8] *Measurement and Verification for Demand Response*, Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group, February 2013, https://eaei.lbl.gov/sites/all/files/napdr-measurement-and-verification.pdf.

ownership of the customer relationship. It is important to be clear about which party owns each function and which is in a supporting role to avoid competing efforts amongst parties.

b. **Agreement with the customer:** In the absence of a pay-for-performance structure with the vendor, then PGE can own the agreement with the customer, as opposed to the implementation vendor owning the agreement. To the extent possible, PGE should create a standard payment structure for all customers and the vendor to eliminate individual negotiations between the vendor and each customer.

c. **Marketing and recruitment:** If PGE has staff available that can open up prospective participants, the vendor could provide technical support to make prospects comfortable with participation in the program and help close the deal. In this scenario, a vendor would provide technical sales support, rather than pure customer sales resources, with PGE leading the marketing and recruitment. This would provide opportunities for PGE to have more contact with the customer and have more control over program-related branding.

d. **Technology and enablement expertise:**

    i. A primary responsibility of the vendor would be to provide technical implementation support. The vendor would install and enable the equipment at the customer site, help the customer develop a curtailment strategy, and provide ongoing technical support to troubleshoot under-performance, refine the curtailment strategy, and potentially provide ongoing customer support via a call center (if desired by PGE).

    ii. Vendors should be asked for solutions that can be implemented using customers' existing interval meters to reduce program costs. PGE should then carefully weigh the reduced costs proposed by the vendor against the reduction in the value of the data to the customer.

    iii. Assuming PGE can use its existing DRMS for dispatch, there is no need to use an implementation vendor's DRMS.

e. **Exit strategy:** Ensure that expectations are clearly laid out for who owns the DR equipment at the end of the contract term, with a buyout clause specified, if the vendor owns the equipment over the course of the program.

**Table 1. Roles and Responsibilities for C&I DR Program**

| Business Function | Responsible Party | | |
|---|---|---|---|
| | PGE | Implementation Vendor | DRMS Vendor |
| a. Define Program Parameters | P, A | - | - |
| b. Marketing, Customer Recruitment and Outreach | P, A | p | - |
| c. Contract with Customer | P, A | - | - |
| d. Provision of Metering | P, A | - | - |
| e. Provision of Technology Products and Services | - | P, A | - |
| f. Technology Installation and Enablement | p | P, A | - |
| g. Initiate Load Control Events | P, A | - | p |
| h. Data Support and Performance Analysis | p | P, A | p |
| i. Billing and Settlement | A | P | p |
| j. EM&V[9] | P, A | - | p |
| k. Customer Service and Satisfaction | p, A | P | - |
| l. Coordination with Energy Trust, KCMs, and Other PGE Programs | P, A | p | - |

*Level of Responsibility:*
A = Accountable (answerable for the correct and thorough completion of the deliverable or task, and often the one who delegates the work to the performer)
P = Perform (carries out the activity)
p = Performs with a lower level of responsibility than P
Blanks indicate that the party is neither accountable nor responsible.

2. **Focus the program marketing and delivery around the benefits to the customers:**
   a. **Highlight the corporate social responsibility benefits of participating in program marketing.** PGE should also investigate channels for externally showcasing current participants, such as through case studies or co-advertising with one of the customers to feature that customer through the program promotion.
   b. **Revisit the financial incentives that can be cost-effectively provided to customers**, including the level of financial support or financing that can be offered for automation. Demand response participation requires indirect costs on the part of the customer, including transaction costs and the value of service lost. To a customer considering participating in the program, the value provided by the program must

[9] Note that PGE is responsible/accountable for hiring an independent third-party to perform the EM&V.

outweigh these costs. While financial incentives are not the only benefit that customers consider, they generally must compensate for all or most of the indirect costs of participation (e.g., curtailing production, paying overtime for after-hours curtailment, installing new systems, etc.). Several non-participants indicated that the current program value does not perceptibly meet that threshold for their business.

c. **Enhance the real-time energy information system and promote its value to customers.** Customers are most interested in using the real-time energy information system to understand how they performed during events and to identify non-essential uses of energy within their facility. PGE could enhance the value to the customer by including case studies or workshops to show how customers can use the granular data for diagnostics.

   Current participants use the energy information system to varying degrees, with one of the key barriers to using more frequently is having limited time available to review the information. To the extent practicable, PGE should work with the vendor to ensure the system provides streamlined access to energy data and ease of use. Two customers also expressed interest in having "more real-time feedback on financial benefits" by seeing the incentives from events sooner after the event through the program portal.

d. **Package DR marketing and participation with other EE incentives**, including the SEM, Energy Tracker, and Energy Expert programs. This provides customers with more up-side to offset the effort and hassle factor of participating.

3. **Enhance education for both participants and non-participants:**

   e. **Non-participants:** PGE should emphasize clear, upfront communications to non-participants about the benefits of the program and the perceived costs, particularly in terms of how the program might affect their operations. Several non-participants expressed concern about impacts to occupancy comfort, which in many cases is something that can be overcome through customer education and an appropriate curtailment strategy. When current participants were asked what PGE might do to reduce barriers to participation for non-participants, several participants thought that information from current participants explaining how participation has impacted their business would help encourage more customers to participate. PGE could highlight the existing customer case studies on the Energy Partner website in initial discussions with non-participants and potentially identify current participants who can champion the program to other customers.

   f. **Participants:** One customer suggested organizing a forum for ongoing participants to interact and discuss ideas for curtailment strategies and lessons learned. Alternatively, PGE could host periodic webinars where customers could share best practices and lessons learned. A couple of customers also expressed interest in receiving help educating stakeholders within their organization about the benefits of the program and explaining why comfort or production might be temporarily impacted.

4. **Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust's day-to-day processes with minimal overhead:**

   g. **Streamlined processes:** Given competing priorities for Energy Trust staff's limited time, PGE should strive to streamline the efforts required by Energy Trust program managers and contractors for cross-marketing.

   h. **Coordinated customer touchpoints:** This program needs to be sensitive to customer fatigue by coordinating touchpoints to the extent possible, since some customers may have already been contacted about the Energy Partner program by EnerNOC or their KCM, in addition to the Energy Trust contractor, who does the cross-marketing to the customer.

   i. **Consistent contractor touchpoints:** Energy Trust contractors are currently blending in discussion of the Energy Partner program, where appropriate, and if customers have questions. PGE should build in consistent touchpoints (e.g., quarterly) to ensure that cross-marketing the Energy Partner program continues to be a priority for the Energy Trust's contractors.

j. **Training curriculum:** The Energy Trust suggested incorporating DR into the SEM curriculum, with an emphasis on "what is DR," what makes good DR opportunities, and how it relates to demand management. This approach would help promote DR, but would also help enhance the value proposition to the customer for participation in SEM. While this approach would market more broadly than the targeted approach PGE has used previously, it shifts the focus away from providing customers a particular "product," while opening the door for conversations about Energy Partner and serving as a foundation for expanding the program reach beyond customer segments historically targeted.

k. **Technical alignment:** At a high level, there is overlap in the use of energy information and interval metering between the Energy Partner and SEM programs. However, EnerNOC required a separate energy information management system and meter that did not match the needs of the SEM program, particularly for industrial customers with unique production data. While it may ultimately be infeasible to find a system in the near-term that serves the needs of both programs and is supported by DR providers, PGE should explore this as an option with vendors during the procurement process.

l. **Formal agreement:** Explore options for codifying the terms of collaboration with the Energy Trust in a formal agreement that clearly defines expectations for the arrangement, including opportunities for PGE to cross-market the SEM program. PGE should also clearly state expectations with DR vendors upfront for coordination with the SEM program as part of the procurement process.

5. **Increase marketing to medium-size customers (200 kW to 1+ MW peak load).** Partner with a vendor that is geared toward smaller C&I customers, particularly in the commercial sector.

6. **Evaluate options for using existing interval meters to lower program equipment costs.** If metering is part of a vendor's proposed solution, PGE should ask the vendor for program cost estimates with and without the use of additional meters, as well as any technical limitations or interoperability issues that the vendor might anticipate with using PGE's interval meters. PGE should then evaluate the cost savings against the tradeoffs in more detail.

7. **To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.** By setting initial load curtailment targets low, the customer can start to understand how DR will affect their operations and will start off successful in the program. PGE used this approach with a current participant and saw positive results. The implementation vendor should also discuss different possible operations scenarios in depth with the customer while developing the curtailment strategy to ensure customers can provide accurate estimates of curtailment across varying operational conditions.

8. **Leverage existing and new channels for broader and more continuous customer engagement:**

    a. **KCMs:** PGE should continue to use and grow the role of KCM's as one of the channels for marketing and customer enrollment. If PGE decides to lead marketing and recruitment in-house, the role of KCMs will be particularly important. Opportunities include more clearly defining the expectations for KCM contributions to enrollment in relation to the implementation vendor and providing more training for KCMs specific to the program. Collaboration with account managers in other jurisdictions tends to be most successful when the utility ties program-specific metrics to performance scores, if that option is available to PGE.

    b. **Local technical expertise:** Several participants said that they would have benefited from more upfront implementation assistance with deep technical knowledge of certain end uses. Customers also expressed a desire for ongoing technical assistance throughout their participation for identifying new ways to curtail more. PGE may consider partnering with a local energy engineering firm, such as Cascade Engineering, to provide strategic technical expertise for some customers.

c. **Alternative marketing channels:** Exploration of new marketing channels will be particularly crucial if PGE markets the program in-house. Examples could include offering referral bonuses to building controls trade ally channels for large commercial (i.e., similar to Hawaiian Electric Company), cross-marketing with the vendor who provides PGE's storage solutions, or working through local industry associations and chambers of commerce.

## 3.4 Procurement

Given PGE's unique market and operating environment, rather than offer a traditional RFP solicitation, Navigant recommends that PGE define the situation and the problem, and invite solutions in a very short response format (e.g., with only proposed structures, drivers of pricing, caveats, and indicative pricing). Based on the vendor's responses, PGE would then invite a few firms for a brainstorming discussion that helps PGE think through the issues constructively. Following this working session, PGE would select one of the firms to help modify the program and to deliver it in a new way that addresses the challenges identified.

# Section IV Summary

PGE has faced challenges building C&I DR capacity within its service area, due to issues like limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. However, there are changes PGE can make to increase participation and capacity by refocusing the program as a customer-centric resource comprised of more diverse C&I customers in terms of size and industry type, with an emphasis on education and strategic partnerships for customer outreach. As part of this, PGE should also revisit and prioritize the operational requirements for the C&I DR resource to facilitate flexibility for the customer where possible, while also meeting PGE's operational needs. This new DR philosophy emphasizes flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within the customers' and PGE's operations requirements.

# PGE Advice No. 17-18
# Attachment C
# Demand Response Final Report and Presentation from Hansa

chent

PGE

# Demand Response Final Report and Presentation

## 13 April, 2015

HANSA

Engagement #6531

# Contents



# Objectives and Methodology

chent

- Primary goal: Pick marketing communication messaging that will strengthen the Energy Partner℠ brand and increase participation in demand response programs.

Core objectives:

- Find messaging that resonates, without jargon
- Test which messaging resonates with different customer groups (facility, sustainability, finance/executive)
- Rank key messages in order of importance to customer groups

- In-depth interviews:
  - 30 participant interviews
  - 30 minutes in length
  - Conducted face to face or by phone (21 by phone, 9 face to face)
  - Recruited from PGE lists

# Respondent Profile: Good Mix of Roles and Industries

- Decision-makers for energy efficiency programs in a mix of industries within Energy Partner[SM]'s sweet spot
- Research participants met minimum thresholds for power use

| Industry | Interviews |
|---|---|
| Food & Beverage | 7 |
| Water/Waste Water | 6 |
| Industrial Manufacturing | 6 |
| Tech/Data Center | 4 |
| Commercial Real Estate | 7 |
| **Total** | **30** |

**Sample Job Responsibilities**

- CEO/Principal
- Production
- Operations
- Controller
- Store manager
- Property manager
- Maintenance
- Farm manager

**Sample Businesses**

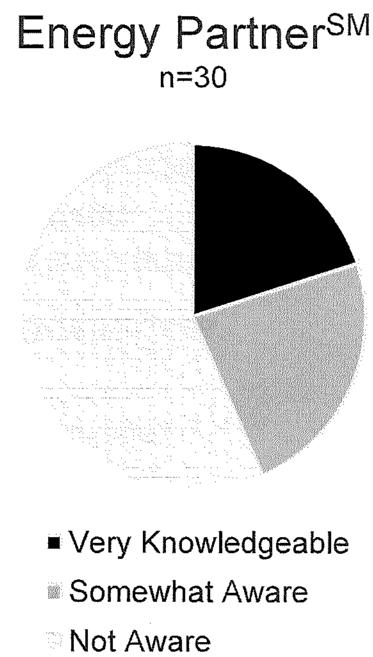
- Grass seed growing and storage
- Apparel manufacturing
- Woodworking
- Storage facility management
- Egg producer
- Grocery store

# Respondent Profile: Low Overall Awareness of Energy Partner℠



- Nearly half of customers who participated say they are not at all aware of demand response programs.
- More customers say they are very knowledgeable about PGE's Energy Partner℠ than about demand response programs in general, illustrating the importance of using customer-centric language.

| Awareness Level | Demand response programs | PGE's Energy Partner℠ |
|---|---|---|
| **Very knowledgeable** | 1 | 6 |
| **Knowledgeable** | 6 | 0 |
| **Somewhat aware** | 9 | 7 |
| **Not aware** | 14 | 17* |




*S04A. PGE has a program called Energy Partner where business customers can get paid to make small reductions in their energy use on hot summer and cold winter days when we're all using more electricity, putting pressure on the grid. Are you aware of this program, or anything like it? Sometimes utilities call this kind of program "demand response." READ LIST.

S04B. If at least somewhat aware at S04A: What is your level of knowledge of PGE's Energy Partner Program?

*Includes 14 who said "not aware" to demand response question (and were not asked the follow-up question).*

# Executive Summary: Energy Partner℠ is Appealing

- Two-thirds of participants have at least some interest in Energy Partner℠.
  - Saving energy and getting paid for it is an appealing combination as long as there is no hidden rate hike to pay for the compensation.
  - It's essential for each company to maintain control of how and when they participate in Energy Partner℠.
- Customer perception of an energy reduction energy event translates to a high-usage period where Energy Partners ease strain.
  - Understanding of the length of an event varies from hours to days or more.

# Executive Summary: Strong Concerns Limit Participation

- While the idea of cash for participation attracts positive attention, customers have worries about being an Energy Partner$^{SM}$.
  - Continuing to meet business and customer commitments is a prime concern.
  - Businesses also worry about losing control of their access to the power they need. Is it really their choice or PGE's choice?
  - Some see a Big Brother aspect, thinking PGE will know too much about power use and move to mandates about how power is used.
  - The specter of regulatory requirements and how they may be at cross purposes with Energy Partner$^{SM}$ looms large for those in heavily-regulated industries.

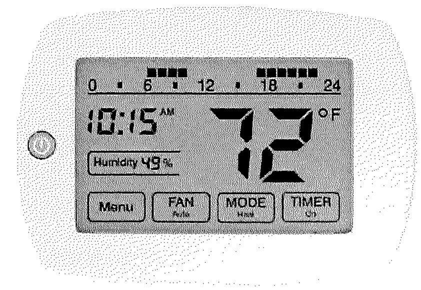
# Executive Summary: Multi-Step Communications Required

- Customers want to know more about Energy Partner[SM] and have suggestions about how they would like to be approached.
  - Email is the logical first step for outreach with a follow up by phone or in person so PGE and the customer can learn more.
  - Getting buy-in from industry leaders and industry organizations will give Energy Partner[SM] validity and encourage others.
- Customers confess to not knowing much about energy saving programs in general, let alone programs like Energy Partner[SM].
  - They are uncertain about where to look for new programs.
  - Confusion exists about how Energy Star, Energy Trust and LEED programs relate to PGE programs.

# Detailed Findings: What Is Energy Partner℠?

# Energy Partner℠: What Is It?

To serve as background for consistent understanding across interviews, customers heard the following description of Energy Partner℠ at the beginning of the interview:




- *During hot summer and cold winter days, we all use more electricity, putting pressure on the grid, energy prices and the environment. To help keep power reliable, affordable and sustainable, PGE pays business customers to reduce or shift their energy needs during these peak periods.*
- *In other words, for every kilowatt you don't use, you get paid.*
- *Being an Energy Partner℠ doesn't mean "turning off the power" or interrupting business. Instead, PGE works with you to identify ways to make small changes, customized for your business, that add up to real savings. Whether it's changing when you charge equipment, or turning the thermostat up or down by a degree or two, you choose the solutions that work best for your business – and in return, you get a check from PGE.*
- *It's your plan, and you stay in control.*
- *On a high-demand day, PGE alerts your business that an energy reduction event is starting. The strategies you selected can go into effect automatically, or you can choose to opt out that day with no penalties. It's always up to you.*

# Energy Partner$^{SM}$: In the Words of the Customer

## What Is Energy Partner$^{SM}$?

*"There's a possibility of saving money during peak usage times, where you adjust the way you do business during those times to save energy."*

*"It's a program designed to induce you to save energy when possible and you get compensated in the process."*


"It's partnering with PGE to manage our energy use with specific things we can do, by season or day, to reduce energy usage and save money."

A word about word clouds: The size of a word indicates the frequency of use for that word across respondents as they describe Energy Partner$^{SM}$. Word color and placement are randomly assigned.

# Energy Partner$^{SM}$: Would a Program Like This Appeal to You?

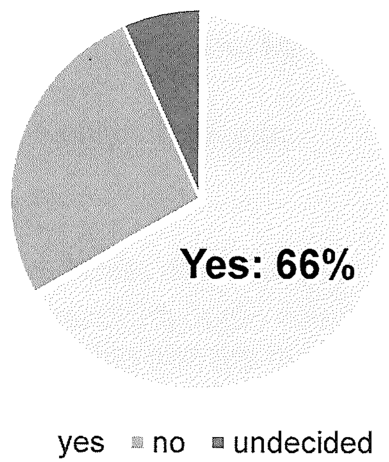
## Sounds Good

**It's good for us**

- *"If there is a way to save money or it brings a check from PGE, I would welcome that but I don't always have the luxury to be able to do that."*
- *"If it's free, I would want to be in it so we could see what our usage is and study it. It's a way for us to see what we're using so we can see what can be done to save."*
- *"It would be worth looking into. I like reducing costs, and right now we spend about $250k a year on electricity."*

**It's good for the environment**

- *"We like to consider ourselves a green company, so we would be interested in looking at anything that could help."*
- *"I'm environmental and that appeals to me. Getting a rebate check is always nice too."*
- *"I think it's good for the environment and for other users so that everybody is conscious of what's going on."*




## Not for Us

**Interferes with business**

- *I don't think it would work too great because most of our electricity is for irrigating, and when it's hot we need to irrigate."*

**Beyond our control**

- *"Being a big store, we have doors opening and closing and we just can't control the cold air that blows in."*
- *"That's hard because our energy use goes up and down depending on how much we're receiving or selling, how our motors are running and so on." It doesn't really fit us."*

**Too little energy to matter**

- *"We're a small office, it would be very minimal to try to do something like that."*

**Doesn't fit our lifestyle**

- *"But you can't adjust times in an office. You're 7-5, 8-5, or whatever the hours are, and at 5-6pm there's a herd of people heading for the front door."*

## On the Fence

**What else can we do?**

*"We've already done work with Energy Trust. I don't know what more can be done. It would be nice to be more efficient but I don't know how."*

**We don't want to endanger our business**

*"The largest [concern]: our type of operation is difficult to adjust."*

# Energy Partner℠: In the Words of the Customer

## What Is an Event?

Customers describe an event through several lenses: power usage, community and business involvement, and power reduction.

**Power Usage**

- *"You're asking partners to use less power during that time, if possible."*
- *"I think that means cutting back on power usage in some manner."*

**Community and Business Involvement**

- *"When there's high demand due to heat or cold and the grid is stressed people need to start working for the good of the community."*
- *"PGE is asking businesses to reduce their power usage to help mitigate the peak usage for a given day."*

**Power Reduction**

- *"A way of lowering the power needs in the building for that time period."*
- *"On a peak demand time you get notified and they want you to reduce your peak."*

The occasional customer sees a loss of control.

- *"Someone other than myself has control of the energy and is reducing or manipulating whatever parameters to create an energy reduction."*

## How long is an event?

Given what they knew about Energy Partner℠, customers speculate on the length of an event.

**A matter of hours …**

- *"Probably a business day from 8:00 to 5:00."*
- *"Four hours of less."*

**Weeks? Or Months?**

- *"A week or longer."*
- *"One to three hours at the peak time of day."*
- *"A week or a month"*

**Even More**

- *"A full season."*
- *"All summer when it's really hot. Shorter in the winter, maybe?"*

# Energy Partner$^{SM}$: Benefits of Participation Not Just Financial

## What Do Customers Get?

Customers focus on saving money but they also mention reducing power use, enhancing corporate image and preserving the environment.

### Reduced Power Cost

- *"I'm going to say that if we can save money and reduce the cost of energy, that is the ultimate benefit."*
- *"It comes down to dollars and cents. If it's something that can affect the bottom line positively, then I'm all for it."*
- *"Potential lower cost, not only in near-term but also in the long term."*
- *"The company saves money, and we're always looking for ways to save."*

### Responsible Energy Use

- *"Overall this program would help with electrical use because it would spread out the usage instead of peaks and valleys."*
- *"Increased awareness of energy use onsite."*

### Building an Image of Responsibility

- *"A personal reward, knowing you did something good for the environment."*
- *"The biggest is your public image. It's being able to put an icon on our literature saying we're part of this Energy Partner$^{SM}$ program so we're working to promote sustainable energy practices."*

### Environmental Benefits

- *"It's green like dollars to us, but also green like saving the forest."*

### Compensation No Matter What

Customers like the idea of a monthly check, but wonder if there's a catch.

- *"I like getting compensated even without an event. Where is the money coming from though? Will they raise the price on something else to cover that?"*
- *"That sounds like a win/win; how they can afford that?"*
- *"I don't understand how you could compensate people if there are no events. How do you compensate someone for not actually participating or saving energy. That just doesn't make sense."*
- *"I don't think you should be compensated for signing up. That doesn't sound financially prudent to me. It sounds a little wasteful."*

# Energy Partner$^{SM}$: Barriers Rooted in Fear, Lack of Understanding

## Why Not Participate?

PGE's customers tend to think about their commitments to their own customers and employees. They also have trouble visualizing how the program applies to them, and they wonder how much work it will be to implement. Some are concerned about PGE having too much information about how they operate, or too much control over how they do so.

### Business Commitments

- *"Our equipment can't really be turned off."*
- *"My customers couldn't be affected."*
- *"My clients' comfort level is big."*
- *"We want out employees to be happy and satisfied."*

### Doesn't Seem to Apply to Us

- *"I don't know what we could turn off or turn down to help out. I wonder if it's applicable to us, and I just don't know where we'd make our cuts."*
- *"It just doesn't seem practical for a grocery store."*
- *"Our equipment runs to make us money."*

### Too Much Work

- *"Is there an extra layer of accounting?"*
- *"We don't know how to do it."*
- *"Are there forms, surveys, paperwork?"*

### Big Brother

- *"If you put yourself under the spotlight of a program that puts more of a focus or scrutiny on what you do, is it going to put you in a predicament where you get involved with mandates?"*
- *"So there is always a risk that if you open your doors to opportunities that you might also be opening your doors for an unanticipated outcome."*
- *"The utility companies make money every time they come up with a new program, and that justifies increased rates."*

## Compliance Concerns Are Significant Barriers

Companies in the food and water quality industries or companies that touch on those areas think first and always about regulatory and legal compliance.

They cannot modify their environment without reassurance they will not run into regulatory problems, legal risk or endanger the public.

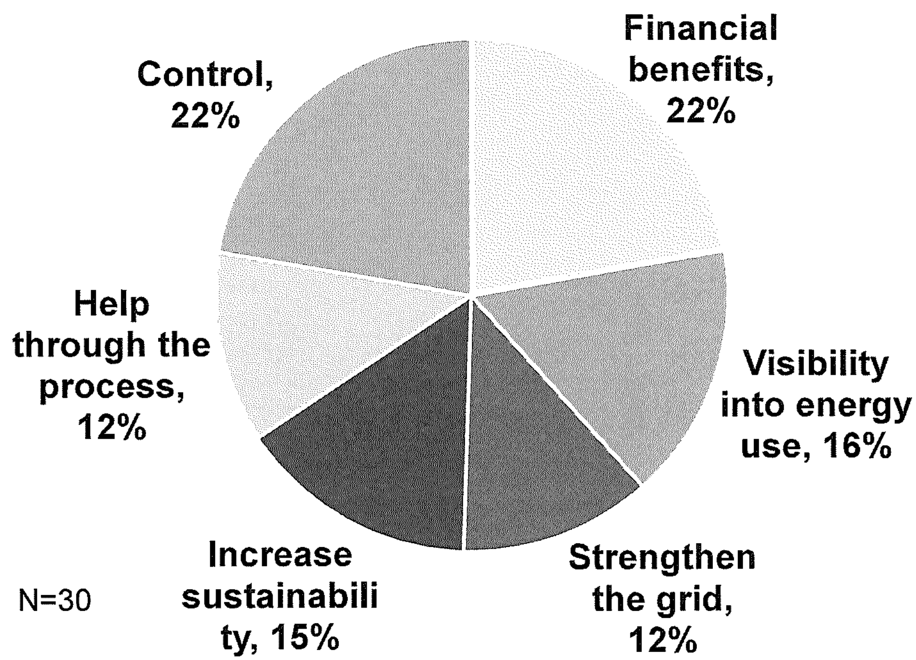
- *"Under FDA regulations there are temperatures we have to maintain to protect food safety."*
- *"We have to watch out for public health and the environment and if it means we have to run during high peak times that's what are required to do by law."*
- *"Violating legal mandates."*

# Detailed Findings: Communicating with the Customer

# Communicating with the Customer: All Themes Resonate

Customers considered six themes related to Energy Partner℠. They were given 100 points to allocate among the themes, assigning points to show the relative importance of each theme to participation in Energy Partner℠.

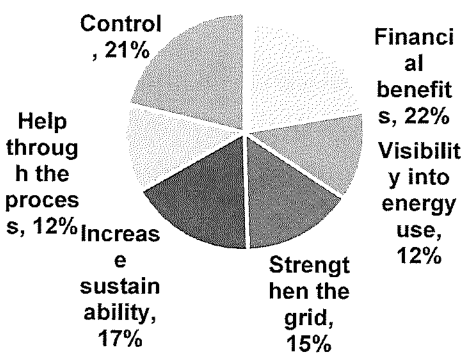
Overall, reactions to the themes split into three tiers with Financial Benefits and Control at the top, followed by Sustainability and Visibility. Help Through the Process and Strengthen the Grid sit at the bottom for importance.



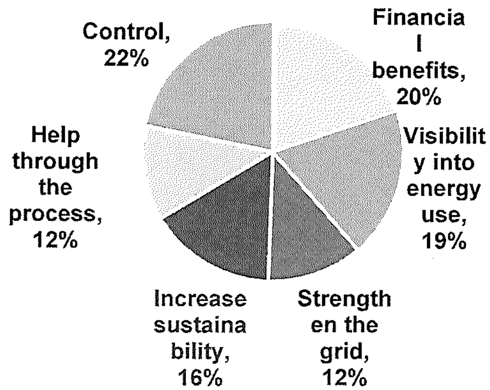

N=30

# Communicating with the Customer: Themes by Industry

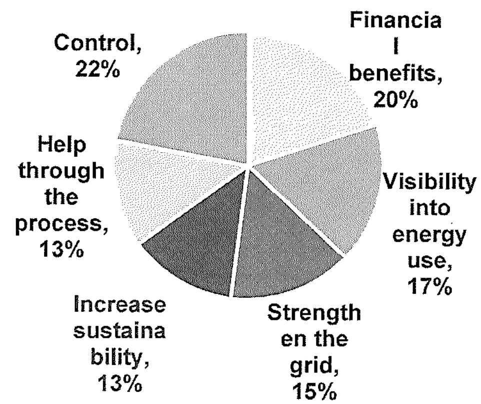
Although the relative importance of the themes is fairly consistent across industries, Industrial Manufacturing stands out among the groups for interest in Financial Benefits, and Control resonates with Water and Waste Water Storage organizations.



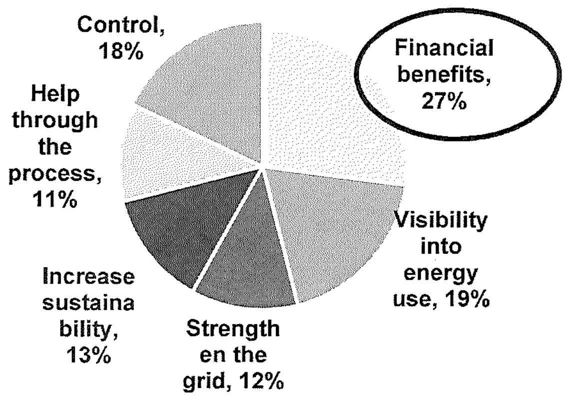

**Commercial Real Estate, n=7**



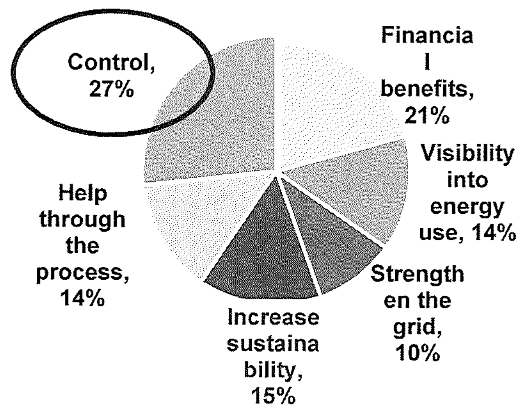

**Food & Beverage/ Cold Storage, n=7**




**High Tech/ Data Centers, n=4**




**Industrial Manufacturing, n=6**



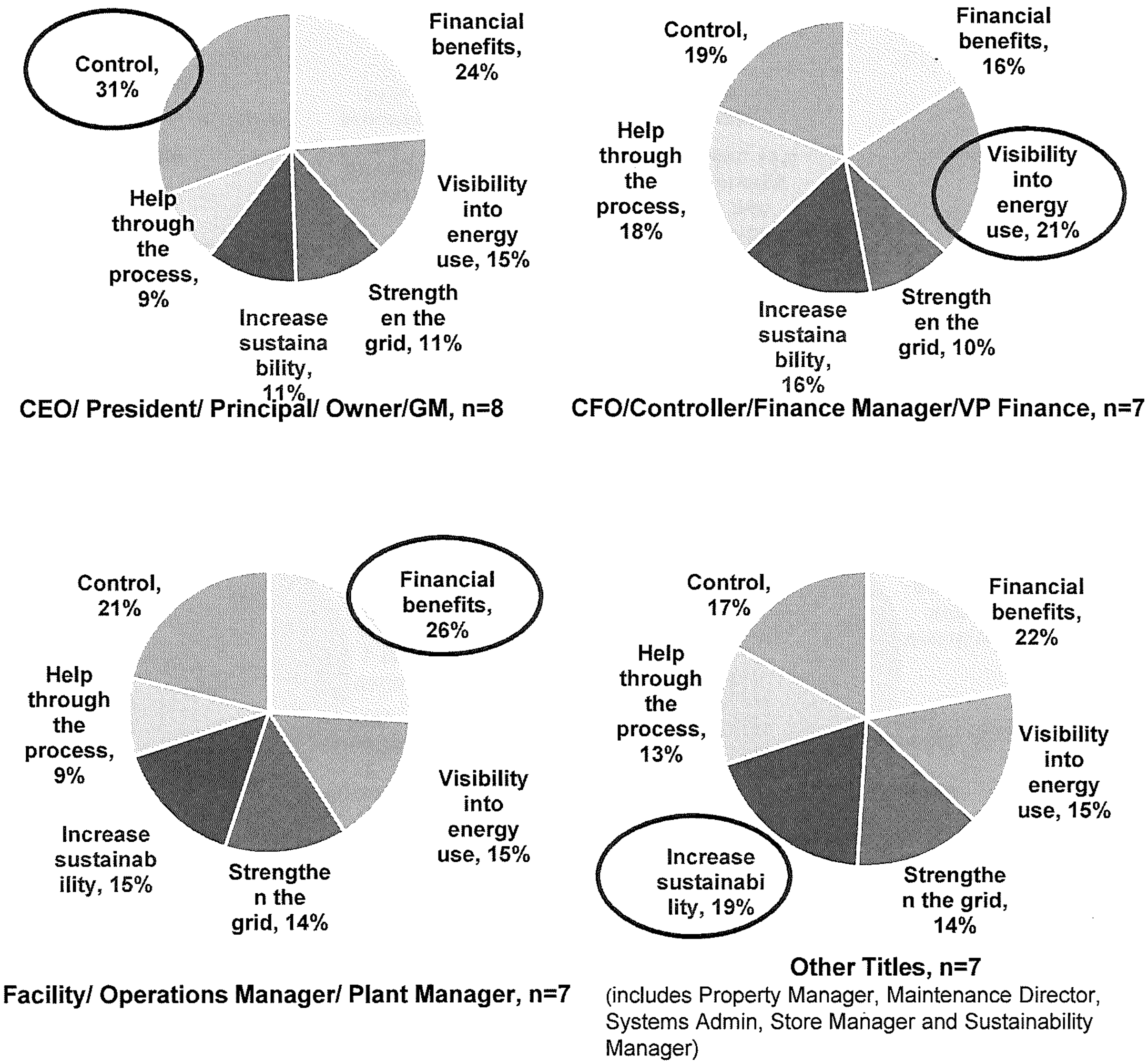

**Water & Waste Water Storage, n=6**

# Communicating with the Customer: Themes by Job Title

**Who Is Interested in What?**

Using job title as a lens, each set of job titles has a unique focus.

- Control is the outstanding theme for the CEO segment
- CFOs find Visibility into Energy Use the most compelling theme
- Facility and Operations Managers look most closely at the Financial Benefits theme



# Communicating with the Customer: Top Phrases Strong

Customers heard a series of phrases that support the Energy Partner℠ themes and selected the phrase that best supported each theme. The following phrases are the most-often selected phrases by theme. Two-thirds of the customers selected the phrase that emphasizes PGE's commitment to partnership.

**Theme: Financial benefits - You get a check**

√ Get paid for managing your energy use (Selected by 13 customers)

**Theme: Visibility into energy use – Tools to shine a light on your energy usage patterns**

√ Get a no-cost assessment of your facility's energy use and operations (Selected by 16 customers)

**Theme: Strengthen the grid - It's good for everyone**

√ Businesses like you are supporting their community while improving their bottom line (Selected by 13 customers)

**Theme: Increase sustainability – Your company is part of the solution**

√ By being an Energy Partner℠, you help create a greener tomorrow (Selected by 12 customers)

**Theme: Help through the process - PGE makes participation easy**

√ PGE works with you to identify a customized solution for your business (Selected by 20 customers)

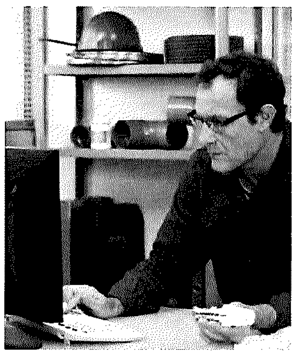
**Theme: Control - You're in control**

√ You choose the solutions that work best for your business (Selected by 10 customers)
√ The strategies you select can go into effect automatically, or you can choose to opt out that day with no penalty (Selected by 10 customers)

# Detailed Findings: The Last Word

# Communicating with the Customer: Talk to Me

**Email** is the choice for first, introductory contact for Energy Partner℠. Once a connection has been established, then a more direct method such as **face to face, phone or detailed information sources** move the process forward.



**Step One:**

- *"Email so I **don't have to look too hard**."*
- *"Email with a **link**."*
- *"Emails to **build it up**."*

**Step Two:**

- *"A **phone call** to the right people."*
- *"Face to face to **get to know our business**."*
- *"**Directions to the web site for more information** or information packets to read and absorb when we have time."*

For some industries, customers suggest taking a group approach. They recommend forging a **partnership between PGE and an industry organization or influential users** to show validity and encourage participation.

- *"**Pick some of the largest users** and schedule meetings to go over the program. Let them assist with ideas for the program."*
- *"**Get active with the movers and shakers in the industry**. These are the people who recognize the advantages."*
- *"**Partner with organizations like BOMA** and offer continuing education hours as an incentive to listen."*
- *"**Notifications in professional publications and newsletters would attract attention** and get the message out to a wider audience."*

# Energy Partner$^{SM}$: Specifics Will Interest Customers

Customers are interested in Energy Partner$^{SM}$, but … unanswered questions hinder full acceptance. In short, customers want to be sure Energy Partner$^{SM}$ will not interfere with business as usual. And they don't want to retrace the steps they have taken with other energy efficiency programs.

**What about my industry?**

- *"I need to know how this fits for farms."*
- *"PGE needs to demonstrate they understand our business needs and challenges."*
- *"They're going to have to survey our site and show they can definitely save us money."*

**What's my part?**

- *"What specifically are we being asked to do?"*
- *"We'll need help determining what we need to do."*

**How does this affect the way I do business?**

- *"We don't want to upset the apple cart of the organization."*
- *"We need some way of visualizing a way to do it that doesn't directly impact our ability to do business."*

**What if we already participate in other energy programs?**

- *"Explain to me how this is different from the other energy programs. We're heading into a saturation of energy programs. Participating in Energy Star and LEED is not inexpensive and it's time consuming. Why should we do this, too?"*

# Interpretations and Conclusions

# Interpretations and Conclusions

- Customers see their business through the lenses of serving their customers and maintaining service standards and regulatory compliance.
  - They need to know what changes they can make that would not affect customer comfort or detract from the way they do business.
  - Customers hear the message they will be in control, but they need solid reasons to believe in the promise of total control.

- Customers are ready to hear about real numbers with regard to how much they will save, how much they have to contribute and the real extent of what they must commit to.
  - Emphasizing PGE's energy assessment and small changes is important to increasing participation.

# Interpretations and Conclusions

- Showing real results and benefits of Energy Partner[SM] based on the experiences of existing participants will open the door for many businesses to take a closer look.
  - Industry-specific case studies that focus on the kind of changes that make a difference and their effect on the bottom line, including estimates of what a monthly check can be, will help customers look at Energy Partner[SM].

- Partnerships with industry leaders and organizations along with the support and cooperation with recognized energy saving programs will appeal to businesses that may be uncertain about participation.
  - Energy Partner[SM] is a community program; having the support of community and industry leaders emphasizes the nature of the program.

# Interpretations and Conclusions

- Messages that emphasize financial benefits and customer control of Energy Partner(SM) are most effective in communicating the value of the program to customers.
  - In support of the financial benefits theme, customers prefer phrasing that puts the customer first and cites customer management that leads to rewards.
    *"Get paid for managing your energy use."*
  - Similarly, customers are drawn to *"You choose the solutions that work best for your business"*, emphasizing customer choice to describe control of the program.

- Visibility into energy use and sustainability follow financial benefits and control in order of importance to customers.
  - The opportunity for a *"no cost assessment of energy use"* is appealing.
  - Customers like knowing they can demonstrate they care about a *"greener tomorrow"*.

# Interpretations and Conclusions

- Audience segments react differently to Energy Partner$^{SM}$ themes, suggesting the value of varied approaches by audience.
  - CEOs want to know they will be in control.
  - CFOs like the idea of having new visibility into their company's energy use.
  - The financial benefits theme makes sense to facility and operations managers.
  - Not surprisingly, sustainability managers are in the group that wants to hear about the sustainability benefits of Energy Partner$^{SM}$.

# Thank you!

## Q&A

PGE

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**About Hansa**

**Hansa GCR is a full-service market research and consulting firm. Looking through the lens of the customer experience and applying psychological principles of human motivation, it offers best-in-class services in areas relating to Customer Relationship Equity, Market Assessment, Branding, and Product/Service Innovation. Hansa GCR is part of R K SWAMY HANSA, an emerging global group with 1,500+ professionals offering Creative Communication, Market Research, Data Analytics, Brand Consulting, Interactive and Healthcare Communication services.**

**For further information about Hansa please visit us on the Web at www.hansagcr.com, contact us via email at customresearch@hansagcr.com, or call us at: +1 503.241.8036.**

PGE Advice No. 17-18
Work papers
Prices for Schedule 25 and 26
provided in Excel format

The Work Papers to this filing were purposely omitted.

If you would like to receive a copy, please contact Mary Widman, at (503) 464-8223 and request for PGE Advice No. 17-18.

## Attachment B.

## AMI Operational Savings Report (July 31, 2012)

PGE

# AMI Operational Savings Report

(July 1, 2011 to December 31, 2011)

## Introduction

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult." PGE did not file a general rate case in 2011, and thus provides this report.

If all aspects of AMI had been completed by December 31, 2010, as originally scheduled, calendar year 2011 would have been the first full year after completing AMI deployment. However, due to certain delays related to implementing IT process improvements, the AMI project close-out did not occur until June 30, 2011. Thus, many operational savings were not available until the second half of 2011.

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE (the Parties) agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011 and the second covering January 2012-June 2012. For the purpose of comparison and savings calculation, the Parties agreed that calendar year 2007, escalated to 2011 for known cost increases, provides the appropriate baseline for establishing AMI project savings. Pursuant to this agreement and Order No. 08-245, PGE provides the following AMI Operational Savings Report for the half-year ending December 31, 2011.

## Summary

Table 1, below, summarizes the net actual AMI Operational Benefits for the six-month period of July 2011 through December 2011:

**Table 1, Summary of AMI Net Operational Benefits Jul-Dec 2011**

| Category | $ |
|---|---|
| **Operational Benefits** | |
| FTE reductions - straight time | 4,220,273 |
| Other labor/contractor reductions | 109,878 |
| Overtime reductions | 239,142 |
| Material and supplies | 176,358 |
| Fuel and maintenance | 381,842 |
| Late pay fees | 861,135 |
| Load forecast adjustment from UE 215 to reflect remote disconnects | 333,689 |
| Additional billings from lost revenue protection | 856,777 |
| Meter accuracy | 780,737 |
| **Subtotal** | **7,959,831** |
| **Additional benefits** | |
| Currently unavailable due to power price decrease | 393,174 |
| Outage management (i.e., pinging the meter) | 203,781 |
| Business Energy Tax Credits (BETCs) | 193,770 |
| UE 215 stipulated benefit | 219,058 |
| **Gross AMI Benefits** | **8,969,615** |
| **Other Incremental Costs** | |
| Non-Labor IT costs | (153,404) |
| Non-Labor communication costs | (111,257) |
| Non-Labor network data operations | - |
| **Net AMI Benefits (for six months, July-Dec 2011)** | **8,704,954** |
| **Annualized AMI Benefits (based on the July-Dec 2011 period)** | **17,409,908** |
| **Projected Benefits – 2012** | |
| Forecasted benefits – additional FTE reductions in 2012 | 1,391,685 |
| **Projected Annualized AMI Benefits 2012** | **18,801,593** |

## Operational Benefits

*FTE Reductions – Straight Time*

Overall, PGE realized approximately 113.2 FTE reductions directly related to AMI deployment by 2011. By taking the average salary for each department and multiplying by their respective FTE reductions or additions, a savings of approximately $2.6 million in straight time labor was calculated. With the addition of labor loadings, FTE reductions accounted for approximately $4.2 million in operational benefits between July and December 2011.

*Other Labor/Contractors*

In PGE's Billing Department, commitments were made to reduce straight-time Labor FTEs (incorporated in above FTE reductions) as well as contractors. Between the 2007 baseline year and 2011, the Billing Department realized approximately 4.5 contractor reductions directly related to AMI deployment. These reductions accounted for approximately $0.110 million in operational benefits between July and December 2011.

*Overtime*

From the reductions in meter readers, there has been a corresponding reduction in overtime costs associated with meter reading. By comparing baseline 2007 overtime costs to 2011, PGE calculated that overtime reductions accounted for approximately $0.239 million in operational benefits between July and December 2011.

*Materials and Supplies*

From the reductions in meter readers, there has been a corresponding reduction in materials and supplies cost in the Meter Reading Department. By comparing baseline 2007 materials and supplies costs to 2011, PGE calculated that materials and supplies costs accounted for approximately $0.176 million in operational benefits between July and December 2011.

*Fuel and Maintenance*

With AMI fully deployed, there has been a corresponding reduction in fuel and automotive costs associated with meter reading. By escalating the baseline 2007 vehicle fuel and maintenance costs the benefits for fuel and maintenance reductions is determined. For the first six months AMI was fully deployed, reductions in fuel and maintenance costs accounted for approximately $0.382 million in operational benefits.

*Late Pay Fees*

One of the significant qualitative benefits of AMI is the ability for customers to select their preferred billing cycle, so that their bill due date is more convenient. With the provision of this benefit, the Oregon administrative rules allow PGE to advance by approximately 30 days the date when customers are obligated to pay a late fee on past-due bills. By comparing the baseline 2007 Late Payment Fees to 2011, we determined that Late Pay Fees accounted for approximately $0.861 million in operational benefits between July and December 2011.

*Load Forecast Adjustment*

In Docket No. UE 215, PGE's 2011 general rate case, we adjusted the residential load forecast by (20,411) MWhs to reflect the reduction in energy use that PGE would achieve from its remote disconnect meters. Because the expected reduction in arrearages has been obscured by the continued weakness in the Oregon economy, we cannot quantitatively establish this benefit from 2011 data. PGE has nevertheless maintained the load reduction to provide this benefit to customers. In UE 189, this benefit was estimated to be $1.4 million with avoided energy costs priced at approximately $66/MWh. In UE 215, when we applied the load reduction, energy costs had declined to approximately $51/MWh, so that of the $1.4 million energy-related benefit, $0.3 million were based on "power prices … beyond PGE's control, we note this aspect of energy-related benefits as being temporarily unavailable but in the future, it is fully achievable." (See PGE Exhibit 300, page 17.) In 2011, energy prices have declined further to approximately $30/MWh. Consequently, the load reduction benefit is $0.334 million between July and December 2011 and the temporarily unavailable component of this energy-related benefit is $0.393 million for half year period.

*Additional Billings from Lost Revenue Protection*

With AMI, PGE's Energy Recovery Department has been able to use newly acquired interval data to increase their success in the identification of energy theft and unaccounted for energy losses (i.e., lost revenue protection or LRP). By comparing the baseline 2007 "lost MWh avoided" to 2011, PGE identified an increase of approximately 8,605 MWh of energy loses that were avoided due to AMI. This accounts for approximately $0.857 million in energy-related savings between July and December 2011.

*Meter Accuracy*

In conjunction with AMI deployment, PGE performed a study to estimate the improvement in meter accuracy between old mechanical meters and new solid state meters. The purpose of the study was to evaluate the new meters' ability to read lower levels of consumption and to correct for older mechanical meters running slower over time. From the study, PGE calculated an operational benefit of approximately $0.781 million.

## Additional Benefits

*Currently Unavailable due to Power Price Decrease*

As noted above, the decline in power prices has increased the amount of currently unavailable energy-related benefits associated with the UE 215 load forecast adjustment. For the July through December 2011 period, this totals $0.393 million.

*Outage Management*

One of the benefits of AMI is the ability for PGE's repair and line dispatchers to "ping" the meters. Pinging the meter allows PGE to determine whether or not a meter has power without the need for a repair or line dispatcher to dispatch a crew. By comparing the average non-dispatch cost savings from 2007-2010 to the non-dispatch cost savings in 2011, we determined that pinging the meter accounted for approximately $0.204 million in operational benefits between July and December 2011.

*Business Energy Tax Credits (BETCs)*

In UE 215, PGE's revenue requirement reflected $1.0 million in state tax credits for BETC's associated with AMI. Based on the Oregon Dept. of Energy's preliminary approval, the BETCs were expected to total $3.5 million and be available over five years as follows:

| | |
|---|---|
| 2011 | $1,000,000 |
| 2012 | $1,000,000 |
| 2013 | $500,000 |
| 2014 | $500,000 |
| 2015 | $500,000 |

Because PGE did not receive final approval of the BETCs until 2012, customers will receive the $1.0 million tax credit benefit for at least three years and until PGE's next rate case goes into effect. By calculating the levelized, net present value of the BETC revenue requirement, we identify approximately $0.194 million in operational benefits between July and December 2011.

*UE 125 Stipulated Benefit*

In UE 215, PGE stipulated to provide customers with an additional $1.7 million reduction to O&M costs (see Commission Order 10-478, Appendix A, page 3). PGE customers will therefore receive this benefit until January 1, 2014, which is the earliest a new general rate case could go into effect. By calculating the levelized, net present value of the O&M reduction revenue requirement, we identify approximately $0.219 million in operational benefits between July and December 2011.

## Other Incremental Costs

*Non-Labor IT Costs*

The incremental Non-Labor IT costs reflect an increase in network and server infrastructure, annual Oracle support and maintenance licensing, and storage to cover the availability requirements for Meter Data Consolidator (MDC). The incremental Non-Labor IT costs between July and December 2011 are approximately $0.153 million.

*Non-Labor Communication Costs*

The incremental Non-Labor Communication costs reflect the regulatory requirement that PGE perform outbound calls to customers that PGE remotely disconnects. PGE contracts with a third party vendor to perform outbound calls to meet the regulatory requirement. The incremental Non-Labor Communication costs between July and December 2011 were approximately $0.111 million.

*Non-Labor Network Data Operations*

The incremental costs in Non-Labor Network Data Operations that reflect the annual support payments for Tower Gateway Basestation (TGB) maintenance, Regional Network Interface (RNI) software, and Radio Frequency licensing are zero because they are covered by credits received from PGE's meter vendor.

## Conclusion

In UE 189, PGE estimated that the AMI operational benefits would be approximately $18.2 million in 2011 (the final UE 189 estimate was filed in November 2007). After six months (July 2011 to December 2011) of AMI being fully deployed, PGE has accounted for approximately $8.7 million in actual operational benefits. On an annualized basis, this equals $17.4 million, which is $0.8 million less than the estimate developed in 2007. Looking forward, however, PGE has achieved additional AMI-related reductions of 8 FTEs by June 30, 2012 and we expect to reduce an additional 7 FTEs by year-end 2012. At fully-loaded, average wages these FTEs are expected to produce an additional $1.4 million benefit, which would raise the annualized benefit total to $18.8 million.

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# Attachment C.

## AMI Operational Savings Report (November 2, 2012)

# AMI Operational Savings Report

(January 1, 2012 to June 30, 2012)

## Introduction

Commission Order No. 08-245 (Docket No. UE 189) approved PGE's advanced metering infrastructure (AMI) program and adopted certain conditions as part of that approval (see Appendix A, pages 10-21). One condition requires that if PGE "does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of 'before' and 'after' states does not become too difficult." PGE did not file a general rate case in 2011, and thus provides this report.

If all aspects of AMI had been completed by December 31, 2010, as originally scheduled, calendar year 2011 would have been the first full year after completing AMI deployment. However, due to certain delays related to implementing IT process improvements, the AMI project close-out did not occur until June 30, 2011. Thus, many operational savings were not available until the second half of 2011.

On July 19, 2011, the OPUC Staff, the Citizens' Utility Board, and PGE (the Parties) agreed to change the time period of the AMI Operational Savings Report from the 2011 calendar year to two semi-annual reports: the first covering July 2011-December 2011 and the second covering January 2012-June 2012. For the purpose of comparison and savings calculation, the Parties agreed that calendar year 2007, escalated to 2011 for known cost increases, provides the appropriate baseline for establishing AMI project savings.

On July 31, 2012, PGE provided its first semi-annual report, covering July 2011-December 2011. After those six months, PGE accounted for approximately $8.7 million in actual operational benefits. On an annualized basis, that equaled $17.4 million.

Pursuant to PGE's agreement with Parties and Order No. 08-245, PGE provides the second semi-annual AMI Operational Savings Report for the half-year ending June 30, 2012.

## Summary

Table 1, below, summarizes the net actual AMI Operational Benefits for the six-month period of January 2012 through June 2012:

**Table 1, Summary of AMI Net Operational Benefits Jan-Jun 2012**

| Category | $ |
|---|---|
| **Operational Benefits** | |
| FTE reductions - straight time | 5,068,904 |
| Other labor/contractor reductions | 100,427 |
| Overtime reductions | 203,337 |
| Material and supplies | 275,836 |
| Fuel and maintenance | 391,596 |
| Late pay fees | 1,115,724 |
| Load forecast adjustment from UE 215 to reflect remote disconnects | 309,144 |
| Additional billings from lost revenue protection | 473,771 |
| Meter accuracy | 780,737 |
| **Subtotal** | 8,719,475 |
| **Additional benefits** | |
| Currently unavailable due to power price decrease | 417,720 |
| Outage management (i.e., pinging the meter) | 205,531 |
| Business Energy Tax Credits (BETCs) | 193,770 |
| UE 215 stipulated benefit | 219,058 |
| **Gross AMI Benefits** | 9,755,554 |
| **Other Incremental Costs** | |
| Non-Labor IT costs | (156,161) |
| Non-Labor communication costs | (119,082) |
| Non-Labor network data operations | - |
| **Net AMI Benefits (for six months, Jan - Jun 2012)** | **9,480,311** |
| **Annualized AMI Benefits (based on the Jan - Jun 2012 period)** | **18,960,622** |
| **Projected Benefits – 2012** | |
| Forecasted benefits – additional FTE reductions in 2012 | 398,215 |
| **Projected Annualized AMI Benefits 2012** | **19,358,837** |

## Operational Benefits

*FTE Reductions – Straight Time*

Overall, PGE realized approximately 122 FTE reductions directly related to AMI deployment by end of June 2012. By taking the average salary for each department and multiplying by their respective FTE reductions or additions, a savings of approximately $3.0 million in straight time labor was calculated. With the addition of labor loadings, FTE reductions accounted for approximately $5.0 million in operational benefits between January and June 2012.

*Other Labor/Contractors*

In PGE's Billing Department, commitments were made to reduce straight-time Labor FTEs (incorporated in above FTE reductions) as well as contractors. Between the 2007 baseline year and 2012, the Billing Department realized approximately 4.5 contractor reductions directly related to AMI deployment. These reductions accounted for approximately $0.100 million in operational benefits between January and June 2012.

*Overtime*

From the reductions in meter readers, there has been a corresponding reduction in overtime costs associated with meter reading. By comparing baseline 2007 overtime costs to 2012, PGE calculated that overtime reductions accounted for approximately $0.203 million in operational benefits between January and June 2012.

*Materials and Supplies*

From the reductions in meter readers, there has been a corresponding reduction in materials and supplies cost in the Meter Reading Department. By comparing baseline 2007 materials and supplies costs to 2012, PGE calculated that materials and supplies costs accounted for approximately $0.276 million in operational benefits between January and June 2012.

*Fuel and Maintenance*

With AMI fully deployed, there has been a corresponding reduction in fuel and automotive costs associated with meter reading. By escalating the baseline 2007 vehicle fuel and maintenance costs the benefits for fuel and maintenance reductions is determined. For the six-month time period of January 2012 through June 2012, reductions in fuel and maintenance costs accounted for approximately $0.392 million in operational benefits.

*Late Pay Fees*

One of the significant qualitative benefits of AMI is the ability for customers to select their preferred billing cycle, so that their bill due date is more convenient. With the provision of this benefit, the Oregon administrative rules allow PGE to advance by approximately 30 days the date when customers are obligated to pay a late fee on past-due bills. By comparing the baseline 2007 Late Payment Fees to 2012, we determined that Late Pay Fees accounted for approximately $1.1 million in operational benefits between January and June 2012.

*Load Forecast Adjustment*

In Docket No. UE 215, PGE's 2011 general rate case, we adjusted the residential load forecast by (20,411) MWhs to reflect the reduction in energy use that PGE would achieve from its remote disconnect meters. Because the expected reduction in arrearages has been obscured by the continued weakness in the Oregon economy, we cannot quantitatively establish this benefit from 2012 data. PGE has nevertheless maintained the load reduction to provide this benefit to customers. In UE 189, this benefit was estimated to be $1.4 million with avoided energy costs priced at approximately $66/MWh. In UE 215, when we applied the load reduction, energy costs had declined to approximately $51/MWh, so that of the $1.4 million energy-related benefit, $0.3 million were based on "power prices… beyond PGE's control, we note this aspect of energy-related benefits as being temporarily unavailable but in the future, it is fully achievable." (See PGE Exhibit 300, page 17.) In 2012, energy prices have declined further to approximately $27.96/MWh. Consequently, the load reduction benefit is $0.309 million between January and June 2012 and the temporarily unavailable component of this energy-related benefit is $0.418 million for half year period.

*Additional Billings from Lost Revenue Protection*

With AMI, PGE's Energy Recovery Department has been able to use newly acquired interval data to increase their success in the identification of energy theft and unaccounted for energy losses (i.e., lost revenue protection or LRP). By comparing the baseline 2007 "lost MWh avoided" to 2012, PGE identified an increase of approximately 9,636 MWh of energy loses that were avoided due to AMI. This accounts for approximately $0.474 million in energy-related savings between January and June 2012.

*Meter Accuracy*

In conjunction with AMI deployment, PGE performed a study to estimate the improvement in meter accuracy between old mechanical meters and new solid state meters. The purpose of the study was to evaluate the new meters' ability to read lower levels of consumption and to correct for older mechanical meters running slower over time. From the study, PGE calculated an operational benefit of approximately $0.781 million for the half-year period.

**Additional Benefits**

*Currently Unavailable due to Power Price Decrease*

As noted above, the decline in power prices has increased the amount of currently unavailable energy-related benefits associated with the UE 215 load forecast adjustment. For the January through June 2012 period, this totals $0.418 million.

*Outage Management*

One of the benefits of AMI is the ability for PGE's repair and line dispatchers to "ping" the meters. Pinging the meter allows PGE to determine whether or not a meter has power without the need for a repair or line dispatcher to dispatch a crew. By comparing the average non-dispatch cost savings from 2007-2010 to the non-dispatch cost savings in 2012, we determined that pinging the meter accounted for approximately $0.206 million in operational benefits between January and June 2012.

*Business Energy Tax Credits (BETCs)*

In UE 215, PGE's revenue requirement reflected $1.0 million in state tax credits for BETC's associated with AMI. Based on the Oregon Dept. of Energy's preliminary approval, the BETCs were expected to total $3.5 million and be available over five years as follows:

| | |
|---|---|
| 2011 | $1,000,000 |
| 2012 | $1,000,000 |
| 2013 | $500,000 |
| 2014 | $500,000 |
| 2015 | $500,000 |

Because PGE did not receive final approval of the BETCs until 2012, customers will receive the $1.0 million tax credit benefit for at least three years and until PGE's next rate case goes into effect. By calculating the levelized, net present value of the BETC revenue requirement, we identify approximately $0.194 million in operational benefits between January and June 2012.

*UE 215 Stipulated Benefit*

In UE 215, PGE stipulated to provide customers with an additional $1.7 million reduction to O&M costs (see Commission Order 10-478, Appendix A, page 3). PGE customers will therefore receive this benefit until January 1, 2014, which is the earliest a new general rate case could go into effect. By calculating the levelized, net present value of the O&M reduction revenue requirement, we identify approximately $0.219 million in operational benefits between January and June 2012.

## Other Incremental Costs

*Non-Labor IT Costs*

The incremental Non-Labor IT costs reflect an increase in network and server infrastructure, annual Oracle support and maintenance licensing, and storage to cover the availability requirements for Meter Data Consolidator (MDC). The incremental Non-Labor IT costs between January and June 2012 are approximately $0.156 million.

*Non-Labor Communication Costs*

The incremental Non-Labor Communication costs reflect the regulatory requirement that PGE perform outbound calls to customers that PGE remotely disconnects. PGE contracts with a third party vendor to perform outbound calls to meet the regulatory requirement. The incremental Non-Labor Communication costs between January and June 2012 were approximately $0.119 million.

*Non-Labor Network Data Operations*

The incremental costs in Non-Labor Network Data Operations that reflect the annual support payments for Tower Gateway Basestation (TGB) maintenance, Regional Network Interface (RNI) software, and Radio Frequency licensing are zero because they are covered by credits received from PGE's meter vendor.

## Conclusion

In UE 189, PGE estimated that the AMI operational benefits would be approximately $18.2 million in 2011 and $18.9 million in 2012 (the final UE 189 estimate was filed in November 2007). During the six-month time period (January 2012 to June 2012) with AMI fully deployed, PGE has accounted for approximately $9.5 million in actual operational benefits. On an annualized basis, this equals $19.0 million. Looking forward, PGE expects to reduce an additional 4 FTEs by year-end 2012. At fully-loaded, average wages these FTEs are expected to produce an additional $0.4 million benefit, which would raise the annualized benefit total to $19.4 million.

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# Attachment D.

# AMI Scoping Plan

# Draft PGE Scoping Plan for AMI Benefits

## I. Introduction

In PGE's most recent general rate case, OPUC Docket No. UE 180 (see PGE Exhibits 800, 2300, and 3000), PGE submitted a proposal for an advanced metering infrastructure (AMI) system. As we explained in the March 2006 filing that initiated that docket: "PGE believes now is the appropriate time to launch an AMI project because the technology is mature and a number of parties have signaled their interest in moving forward with future methods of grid management and demand response. We cannot begin to achieve these goals without AMI." PGE Exhibit 800 at 3. These reasons are even more compelling now. Since March 2006, initial results from our current Integrated Resource Planning (IRP) process indicate that PGE will need to acquire approximately 900 MW of capacity by 2012. Demand-side resource can and should play a significant role in filling this need. Demand-side programs not only help ease pressure on PGE's electric delivery system during peak load times and reduce the risk of interruptions during extreme peaks but, importantly, participating customers reduce their electric bills and save money. No other resource can save customers money as we deploy it. PGE is very interested in demand-side benefits and we are confident that the AMI system we propose will support them. We do not expect implementing demand-side programs to require complicated connections with the information platform because, from 2000 through 2003, PGE had already developed much of the IT software and system integration needed to operate a fully functioning AMI system.

As we began this project in 2005, we initially focused on the operational effects and benefits of changing how we meter customers' usage. We needed to manage the change well, and sound business practices required that we identify and capture what benefits we could as we made the necessary process changes. Pursuant to Staff's requests (in Staff Exhibit 700), we have started and/or completed implementation plans for those changes and benefits that stem from the change in technology. With this document, we add to it our scoping plans for achieving the customer- and system-related benefits that moving to metering grounded in two-way, real-time communication – rather than a monthly manual read – will enable. These fall into the categories of:

- Demand response programs.
- Information-driven energy savings.
- Improved distribution asset utilization.
- Improved outage management.

In 2007, we will develop implementation plans for these benefit categories.

Using the current system cost estimate of approximately $132.2 million, we anticipate $18.2 million in annual cost savings from operational benefits in 2011, after the system is fully deployed. These costs and benefits produce a net present value benefit of approximately $34 million over 20 years of system operation. With the benefits identified in this scoping plan, we estimate that the net present value benefit of deploying AMI now could increase to between $37 million to $80 million (see Attachment 1) depending on customer acceptance of demand-response initiatives and various other necessary assumptions.

## II. Regulatory Status

Based on comments from the OPUC Staff and other parties, PGE agreed to remove AMI from UE 180 with the understanding that we would resubmit the proposal in a separate, non-rate case proceeding. This filing will encompass the accelerated depreciation of non-AMI meters and other NMR infrastructure that is no longer needed by the new system, plus the revenue requirement of the new AMI system less O&M savings throughout the deployment period.

To support this application, PGE agreed to submit the following documentation:

- A detailed implementation plan for the O&M benefits that PGE reasonably expects to achieve as we implement this technology change.
- A scoping plan for customer- and system-related benefits not covered in PGE's original financial analysis. Our proposed AMI system enables or supports these benefits , but most require additional costs or investment .

PGE is submitting the detailed implementation plan for primary benefits in conformance with the description provided in UE 180, Staff Exhibit 700. The scoping plan below includes the following information:

- The benefit categories that PGE will pursue based upon highest perceived benefit versus cost.
- A timetable for implementation plans.
- A range of potential benefits for the specified programs.

During 2007, PGE will develop implementation plans for the specified benefit categories of this scoping plan.

## III. Customer- and System-Related Benefits

In accordance with PGE Exhibit 3000 (OPUC Docket UE 180), PGE submits this scoping plan to support its proposal for an AMI system. This scoping plan addresses the following broadly defined AMI benefit categories:

- Demand response initiatives
- Energy savings prompted by the availability of hourly usage data
- Improved distribution planning
- Improved outage management

Estimating the net benefits of these initiatives is more challenging than with the operational changes because most require additional investment or cost and some entail customer acceptance as a key variable. Where possible, we drew on industry standards and experience, but this is limited and requires that we consider differences among utilities in general. The accompanying spreadsheet documents the calculations for the more complicated estimates. We have provided ranges estimates because, as noted below, typically the most sensitive variables that determine the benefit value depend on either data not yet collected at PGE or on customer acceptance of new programs. Also provided below are the basic assumptions PGE used to estimate the net benefits for specific sub-category initiatives. These subcategories will be the focus for subsequent implementation plans.

**Demand Response**

PGE has a strong interest in demand response. 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. Because PGE needs to acquire, approximately 900 MW of capacity, as identified during IRP planning, we fully recognize demand response as a potential means to supply some of this peak capacity. In addition, AMI-supported demand response programs would be an invaluable resource during the next possible "energy crisis." Many regulators and utilities undoubtedly wished that AMI systems had been in place during the energy crisis of 2001-2002. While a subsequent energy crisis is currently unforeseen and would undoubtedly occur for different reasons, the possibility exists and could occur both rapidly and unexpectedly. If so, AMI systems, and demand response programs in particular, could either help mitigate the effects or be wished for yet again.

Outside of PGE there is a considerable interest in demand response from federal departments and many state regulators. However, as discussed in most regulatory and industry trade meetings on this subject, there is considerable uncertainty in the possible outcomes from program implementation. Typical topics for debate include:

- What is the likely interest among customers?
- How do we encourage high levels of participation?
- What amount of demand shift will customers provide?
- What is the best way to design rates?
- How should we value the benefits of the demand that is shifted?

What are no longer discussed are the requirements for an AMI system to support these programs. PGE's proposed AMI system will provide robust support for future program design.

PGE has been fully engaged in a number of these regulatory and industry forums, in some cases providing leadership for defining the necessary changes. Two overarching conclusions can be drawn from these meetings and these pertain to PGE also.

1. For demand response to be successful, the industry needs to gain experience in implementing, promoting, operating, and evaluating these programs.

2. To participate in a meaningful way, most customers will need major appliances that respond automatically and effectively by receiving utility control and/or price signals directly.

Based on these conclusions, PGE's near term actions will be to develop implementation plans to address the two needs. The first effort will be a plan for a demand response market pilot, and the second, a plan for a market transformation initiative based on the lessons learned from PGE's participation in the NW Grid-Friendly Appliance (GFA) project. While these plans look feasible, cost effectiveness depends – as is always the case – on assumptions that future conditions may cause to change.

<u>Demand Response Market Pilot</u>

At present, we plan an Opt-In, Critical Peak Pricing (CPP) Tariff Pilot for 2009 implementation, targeted at residential customers, with one-time development costs of approximately $1 million in 2008 and 2009. After launching in 2009, our effort would be to reach the maximum participation rate by 2013, with a total of twenty critical-peak price events during the winter and summer. By 2013, we would evaluate and engage in any necessary program re-design to maintain the acceptance rate.

Attachment 2 to this document provides a simple model that includes most of the costs of the program. The model is simple so as to emphasize the sensitivity to three variables that correspond to the chief uncertainties: the number of customers that participate, the average kW load shift per customer, and the value of capacity.

To explore the range of possible benefits, we created a nominal scenario, a low scenario and a high scenario. The range of net present values for the three scenarios varies between a negative value and $27 million dollars. The duration of the program is coincident with the life of the AMI system. Note that $27 million occurs in the high scenario with an assumption of only 10% market penetration. We used this assumption because few opt-in programs at PGE have participation as high as 10%. Changes in societal energy interests, however, could drive a much higher acceptance rate and the benefits would increase accordingly. The following variables represent the primary assumptions used in Attachment 2:

*Customer Participation*
The single biggest uncertainty is customer participation rate. In the nominal case, we assume participation reaches 5% (about 40,000 customers.) In the low case we assume 1.5% acceptance and 10% in the high case. The specific elements of the rate design (and its associated terms), customer education efforts, and how effectively the offer is promoted will likely significantly affect program acceptance. A break-even result requires the fairly large participation of the Low Scenario because of the one-time startup cost of approximately $1 million

*Load Shift*
The nominal average value of 0.5 KW shifted per customer is based on PGE's <u>Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option</u> section on CPP.

Because this estimate is not based on experience in PGE's service territory, actual results could vary considerably. The Low Scenario assumes 75% of this value and the High Scenario 140%.

*Avoided Capacity Cost*

The primary benefit driver is the cost of avoided capacity. Again, with almost no industry experience with CPP programs the appropriate value to associate with capacity is difficult to estimate. One alternative is the annual cost associated with a simple cycle combustion turbine (CT). In PGE's IRP, this value is more than $70/kW per year. We believe this avoided cost may be high, however, for two reasons. First, at least in the recent past, PGE has found capacity resources that cost less than this. Second, there are no restrictions on how many hours a CT provides capacity and a CT provides reactive current support to the transmission grid during peak periods. Gauging from this avoided cost, we used a value of $29 per KW-year in the Low Scenario because this is what we have incurred, to date, to implement resources for PGE's distributed generation program. In the Nominal Scenario we assume a value of $36 per KW-year and $58 in the High Scenario.[1]

Appliance Market Transformation[2]

The residential sector accounts for approximately 25% of PGE's winter system peak demand, from a combination of water/space heating, cooking, refrigeration and lights. Hourly price signals sent to customers might motivate a substantial shifting of this load to less expensive off-peak hours without significant inconvenience to customers, particularly if the decision how and when to participate could be made just once in appliance set-up. Three market barriers presently exist. First, customers are frequently not at home to manage the load when the price signal is sent. Second, the cost to operate individual appliances (much less the knowledge and the ability to change how the appliance operates) is not well understood by customers. Third, electricity is a low involvement product; most consumers of electricity rarely think about it and tend to take it for granted. The solution to this problem is to have appliance manufacturers modify their appliances to (1) "hear" price and/or control signals from the utility, and (2) include a simple control at the appliance so the customer can make a one-time decision about how much of the appliance function they are willing to give up when the price of electricity is high. Having put those elements into place, the actual load shifting would be an automated function triggered by utility price signals. This is the "smart appliance" concept.

Our plan is to define a technology trial for either water heaters or thermostats whereby a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties[3] develop a project to create a 10 MW demand response resource by decreasing the installed cost per kW through an appliance market-transformation approach. As

[1] These avoided cost values are for illustrative purposes and not intended to be indicative of PGE's avoided cost under the Public Utility Regulatory Policies Act.

[2] While the examples that follow focus on price responsive programs, PGE intends to review direct load control opportunities in our implementation plan for demand response as well. Direct load control will also be addressed in PGE's IRP.

[3] E.g. Pacific Northwest National Lab, Bonneville Power Administration, Oregon Department of Energy (ODOE), Northwest Power Planning Council, US DOE, etc.

suggested above, the components of a smart appliance demand response system include (a) a communications-ready appliance, (b) a communications device[4], and (c) a communications method between the customer (or appliance) and the utility (e.g., AMI network).

In the end state of appliance market transformation, the incremental cost to develop a communication-ready appliance is expected to be about $2 to $5 per appliance.[5] When sufficient numbers of such appliances exist, the utility can implement a very cost-effective program simply by mailing communication devices to those customers who choose to participate. Also in the end state, we estimate the communication device to cost between $0 and $20 depending on what communication resources already exist in the home. (At the lower volume of the demonstration, a $40 cost is expected.)

The main objectives of the technology trial are to:

- Prove the concept of a communication-ready appliance to further the goal of a national standard in this area
- Demonstrate a program where control implementation is achieved by providing only communication devices after sufficient appliances are available to warrant the launch of the program.
- Create a technology-assisted, 10 MW demand response capability.
- Demonstrate that the installed cost per controllable kW is greatly reduced through market transformation.

The milestones in this project are to:

- Make available from the usual retail sources new, communication-ready thermostats or water heaters for use in new construction and replacement applications.
- Promote the selection of these appliances through standard program techniques.
- Promote and install a communication device (one most likely compatible with the AMI system) to allow the customer to capture automated-control benefits and reduce their energy costs under a time-of-use (TOU) or critical peak pricing (CPP) tariff. This will occur in the second or third year of marketing the program,

PGE's specific implementation plan for this initiative, which we will submit in 2007, will describe the following actions:

- Detail the costs, benefits, and timeline to implement the project outlined above.
- Explore membership interest in a consortium to demonstrate the smart appliance concept.
- Form the consortium if possible; otherwise, state barriers to formation.

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[4] This would be an after-market, low-cost communication device that would pass price and/or load control signals after plugging the device into the appliance, much like inserting a WiFi device into a computer USB socket.

[5] For the technology trial described here, the estimated cost to get these appliances into the home is almost $100 per water heater. This is because no communication-ready standard for appliances exists today. In addition to a higher appliance cost, marketing costs must be incurred to get the appliances into the home.

*Example Benefit/Cost Analysis*[6]

We assume on-peak contribution of water heaters to be 0.85kW. To create a 10 MW resource, PGE customers must purchase approximately 15,000 "smart appliance" water heaters. We also assume 5,000 water heaters are sold in each of three (3) years—3,500 in the replacement market and 1,500 in new construction. An appliance manufacturer will need to contribute non-recurring engineering cost to the project. PGE will pay for incremental hardware cost at the appliance for an estimated $15 per water heater. PGE's marketing cost per water heater is estimated to be $60. In the second or third year, PGE would promote a direct load control and/or a TOU program to the customers owning these water heaters. To achieve an 80% participation rate, PGE might guarantee an annual bill savings to each customer. This amount, however, should have a near zero fulfillment cost, due to energy usage shifted away from on-peak. We estimate the customer-installable communication device to be approximately $40 apiece and other one-time program costs to be approximately $250,000. Consequently, we estimate the total installed capital cost to be approximately $1.6[7] million for a 10 MW resource or approximately $160/kW.

Without regard to the considerable societal benefits in this demonstration, PGE's annual net benefit on this 10 MW resource, compared to a supply side resource for capacity, varies between zero and $460,000 depending on the actual implementation costs and avoided capacity cost assumed. The details of this calculation are shown in Attached 2.

## Information-Driven Energy Savings

PGE plans to conduct primary research on how to provide customers useful information from interval data. We also intend to develop an information tool based on the results of this research. We also expect this tool to support Customer Service Representatives (CSRs) in their work on behalf of customers.

PGE's hypothesis is that the information tool will reveal energy-reducing strategies that the customer finds valuable to implement. For example, the tool will determine the cost of running a "spare" refrigerator, or determine the bill reduction from reducing the thermostat setting by a few degrees. The tool might lead the customer to discover unnecessary, but always-on devices. These types of strategies could reduce total energy use by 1% to 10% annually. In a program aimed at getting 500 customers per week to use the tool, if 40% of the customers implement an average, 4-year sustained annual usage reduction of 2.5% (or about 250 kWh per year), then the typical year benefit after four (4) years would be about $500,000[8] per year. PGE estimates utility costs, including depreciation of the development and recurring annual costs to be approximately $110,000. Uncertainty exists with all variables implying a wide range in the benefit outcome. Sensitivity in the summary Table 1 is based on customer participation varying from -50% to +100%.

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[6] This example is for a communication-ready water heater; a thermostat trial would have very different results.
[7] $1,600,000 = 15,000*(($60+$15) 0.8*$40)
[8] Based on an avoid energy cost of $50/MWh. 500,000 = $50/MWh * 4* (500 Customers/wk * 40% * 50 wk/yr * 250 kWh saved annual per customer)/1000. See Attachment 2 for calculation details.

The main objectives of the project, by phase, will be:
Phase 1:

- Conduct primary research, develop concepts for information tool, and create requirements.
- Select a vendor suitable for PGE's objectives.
- Create the initial infrastructure to link meter information, an analysis engine, and a web interface for customers and CSRs.
- Focus on aiding the high-bill complaint process.
- Begin interval data collection for the initial customers that will test the Phase 2 information tool.

Phase 2:

- Develop a tool to help customers understand the cost drivers of daily appliance usage and their own behavioral choices.
- The tool will create semi-customized recommendations to save energy.
- Track energy use for customers that use the tool.
- Conduct an evaluation to determine if the information tool makes a sustained and quantifiable impact on the customer's energy use.

The milestones in this project are:

- Second quarter 2007 – Complete research and sign contract with vendor.
- Fourth quarter 2007 – Launch initial application for high-bill complaint process.
- Fourth quarter 2007 – Begin interval data collection for target group of 20,000 customers.
- Second quarter 2008 – Develop and test-launch interval-data dependent information tool.
- Third quarter 2008 – Test tool with customers and make improvements to usability.
- Fourth quarter 2008 – Launch information tool to target customers, with at least 8 months of interval data history. Promote tool sufficiently to get 1,000 participants in first 3 months.
- Third quarter 2009 – Conduct statistical analysis to determine impact of information tool on energy use.
- Fourth quarter 2009 – Make information tool available to all PGE customers.

**Improved Distribution Asset Utilization**

The underlying assumption in the topics discussed below is that the availability of hourly interval data at every point of delivery will allow PGE to compile a detailed load profile on each component of our distribution infrastructure (e.g., every tap line, service transformer, feeder segment between switches) with the objective of improving asset management and overall system efficiencies. Not included in these estimates is the cost to acquire an analysis tool, sufficiently powerful, to analyze the data.

<u>Avoided Service Transformer Failures</u>

PGE has approximately 300 service transformer failures per year, many of which result from overloading. PGE uses a regression tool to identify overloaded transformers based on estimated monthly kWh usage. The ability to collect interval data on 100% of PGE's service delivery points allows a new model to be developed based on actual hourly loadings which would enable PGE to identify transformers that are overloaded beyond normal tolerances on a more accurate and timely basis.

A new regression model could yield, for each service transformer, an estimate of peak loading (percent of nominal rating) as a function of the ambient temperature at the transformer. We estimate that a new tool might make it possible to eliminate as many as 30% of the failures (i.e., 90 transformers per year) before they occur. This would be especially useful given the increasing amount of home air–conditioning load being added by residential customers. With better data, transformers that are overloaded could be identified and replaced with new or higher-voltage transformers before they fail. This enables PGE not only to re-use the transformer at another location but also to be more efficient in planning and scheduling replacements.

To determine a potential benefit, we assume that the current cost to replace a failed service transformer is $500 plus a 3-man crew working two hours at an average cost of $315/hour (including overtime). This results in a cost of $1,130 per transformer. With a planned replacement, no overtime is required and several transformers can be exchanged per trip. Instead of a two-hour emergency replacement, the planned replacement is assumed to be a 1-hour event at an average cost of $270/hour instead of $315/hour. This results in an average savings of $860 per replaced transformer, or typical annual net savings of approximately $77,000 (90 * $860).

In addition, if we assume a reduced customer outage time of 3 hours, an average of four customers affected per transformer, and a $15/hour avoided societal cost per customer during the outage, the societal benefit is about $16,000 per year (90 replacements x 4 customers x 3 hours x $15/hour). Uncertainty in the 30% pre-identification rate puts total net benefit in the range of $40,000 to $200,000.

<u>Delayed Feeder Conductor Work</u>

PGE currently plans approximately $1 million of feeder conductor work per year. These are performed to resolve overloading conditions on sections of the affected feeder.

Assume that PGE defers one-third of its annual work to upgrade feeder conductors, an amount of $333,000, for three years because improved loading data were available from AMI. This is based on an engineering estimate. The estimated reduction in revenue requirement (using a 0.13 multiplier) on deferred hardware costs is approximately $43,000 per year. The additional engineering cost of collecting AMI data by conductor segment could be approximately $25,000 per year. Based on these assumptions, a net benefit can be achieved by year three and for ongoing years of approximately $100,000 per year (see table below).

| **Benefits** | **Year 1** | **Year 2** | **Year 3** | **Year 4** | **Year 5** |
|---|---|---|---|---|---|
| Year 1 Work Deferred | $43,000 | $43,000 | $43,000 | --- | --- |

| | | | | | |
|---|---|---|---|---|---|
| Year 2 Work Deferred | --- | $43,000 | $43,000 | $43,000 | |
| Year 3 Work Deferred | --- | --- | $43,000 | $43,000 | $43,000 |
| Year 4 Work Deferred | --- | --- | --- | $43,000 | $43,000 |
| Year 5 Work Deferred | --- | --- | --- | --- | $43,000 |
| Engineering Cost | ($25,000) | ($25,000) | ($25,000) | ($25,000) | ($25,000) |
| **Net Benefit** | **$18,000** | **$61,000** | **$104,000** | **$104,000** | **$104,000** |

The net benefit is very sensitive to the percent of work that can be deferred each year. The range of typical net benefits would be about $40,000 to $160,000.

**Improved Outage Management**

Avoided Trouble Calls

PGE estimates that for 10% of trouble calls[9] from customers reporting that their power is out, it is subsequently discovered that no PGE outage occurred. These trouble calls could be avoided using the query function in the AMI meter which can determine whether or not power is being delivered to the meter (i.e., customer premise).

To estimate the range of benefits, we assume the cost of a truck and full time employee (FTE) to be approximately $90/hour. If improved outage management capabilities from AMI save one hour at $90 for 10% of PGE's 2,500 outage calls per year, we would save approximately $22,500 per year. The costs to implement the power status check at the meter include training for the 200 employees who respond to customers and automating the assisted look-up functionality in the affected systems. This could require approximately $10,000 to $20,000 in incremental costs. The primary uncertainty variable in our assumptions is the number of avoided truck dispatches. A range of minus 50 percent or plus 30 percent implies a net benefit range of $10,000 to $30,000 per year.

Faster One-Premise Outage Response

With isolated outages involving only one premise, the time between outage occurrence and notification at PGE is currently expected to be longer than for outages affecting multiple customers. This expectation is based on the likelihood of people being away from their homes during work hours and returning to find that their home is without power. For customers, the effects of the longer outage could have consequences; for example, spoiled food, lower productivity in a too cold or too warm house, etc. With the proposed AMI system, Operators can identify instances of isolated outages and create a service order to initiate repairs without having to rely solely on notification from the customer.

Annually, approximately 3,000 outages occur that affect only one customer. If we assume that 25% occur when the customer is not at home and that the average incremental cost impact to

[9] Based on random sample of 2005 Outage Management System (OMS) data.

these customers is at least $15 per outage, the resulting societal benefit would be approximately $12,000 per year, plus or minus 50%. PGE, however, does not yet have an estimate for the cost to integrate AMI with the Outage Management System (OMS). Another consideration is that PGE would have to verify the reliability of the AMI outage data because undetected outages and false positive reports would affect the benefit estimate.

Improved Storm Management

This benefit would avoid the costs to address customers who remain without power after a line crew restores power on their tap line, because the AMI system can detect any remaining, isolated customer outages before the crew leaves the area. Restoring the customer service without having to return later saves approximately one hour for a three-man, two-truck crew.

Assumptions made include the following:

1. One Level 2 outage (affecting 25,000 customers) every year.
2. A Level 3 outage (affecting 100,000 customers) every 5th year.
3. An average of 50 customers restored per crew repair.
4. 10% of repairs leave a customer still out of service.
5. The cost is $315/hour for crew and truck cost[10].

These assumptions imply an average savings of approximately 90[11] crew hours per year, or a cost savings during the storm of approximately $30,000 per year (90 hours x $315/hour). For societal benefits, we assume the customers experiencing the undiscovered outages have five additional hours of outage time. This means approximately 360 customer outage hours could be saved. With an average societal outage cost of $15/hour per customer the societal savings is another $7,000 per year.

The key uncertainties in this analysis are the average number of isolated outages detected by the AMI system in a Level 2 or Level 3 outage, the avoided crew hours from not having to return to the site, and the average extended duration of the outage for the customer. Varying the key variables by minus 50% or plus 50% results in a large range of benefits of $0 to $75,000 per year.

There are unknown costs for information system modifications to: (1) automate meter status checks by distribution element, e.g., by fuse, switch, and (2) improve the quality of electrical connectivity records to ensure accurate analysis. To calculate net benefits, $100,000 in development work is assumed recovered with a 0.20 revenue requirement factor[12].

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[10] For a general outage, we assume our personnel costs based on 50% straight time and 50% overtime. Distribution line workers cost an average of $90/hour for straight time and $120/hour for overtime (including vehicle, equipment and payroll loadings), for an average of $105 per person per hour. Thus, a three-person crew costs an average of $315/hour when responding to a general outage.

[11] Based on the first 4 assumptions 90 = (25,000 + 100,000/5)/50 * 10%.

[12] A multiplier to calculate estimated typical year revenue requirements. We use a multiplier of 0.2 for software and 0.13 for hardware.

Faster Fault Location Identification

About half of PGE's SAIDI[13] (System Average Interruption Duration Index) duration is the result of faults that occur when a substation feeder breaker locks open on a downstream fault. Finding the downstream fault, especially on long rural feeders, is a time-consuming process.

A business partner of our AMI vendor is currently developing a fault detection device that would communicate through PGE's proposed AMI system and help pinpoint the location of faults. If PGE places an average of fifteen (15) fault detectors at strategic locations on our longest 450 feeders (covering about 95% of all customers), then the amount of time required to determine the location of a fault should be reduced considerably. The installed cost of a fault detection device is about $250 to $350 per telemetry point (including a system to report the fault data to the dispatchers); thus, the installed cost of 15 such devices on each of 450 feeders would be $1.7 to $2.3 million. This implies an annual cost of about $260,000 (0.13* $2.0 million).

PGE has about 250 open breaker events per year and we typically assign a three-person crew to locate the fault. We assume the current outage duration is 60 minutes per incident and the average reduction in outage time would be 20 minutes. We further assume fault detectors will aid detection on 80% of these events. Based on average crew costs of $315/hour, PGE would save about $21,000 per year (-0.333 hours x 200 feeders x $315/hour). In addition, these 200 events affect, on average, about 2,000 customers each; thus, PGE could reduce overall customer outage time by about 130,000 hours per year (200 events x 2000 customers x -0.33 hours per customer). Assuming an average societal loss of $15.00 per customer per hour, this saves about $2 million per year. Including the societal savings, there is a one-year payback. The main uncertainty rests with the actual reduction in the time to locate the fault. With a range of 10 to 30 minutes in outage reduction time, the typical year net benefit is $0.8 to 2.7 million.

Reduced Contact Center Cost

Overtime costs at PGE's Contact Center during major storms runs as high as $3,500/hour. Over a typical three-day event, overtime costs can total as much as $50,000. As customers begin to understand and trust the capability of the AMI system to detect outages and facilitate faster restoration of service, in-bound call volumes might go down -- as might the need for CSRs to call back customers to verify restoration.

An average annual benefit of $10,000 per year is estimated based on the assumption that improved outage management and reporting will reduce the incidence of customer calls and re-calls by 20%. However, these benefits must be judged against unknown information system costs to facilitate the needs of customers and CSRs. The implementation plan for this initiative is to better quantify the benefit and to identify specific scenarios where benefits could be realized. After generating a list of the information and/or resources that customers and CSRs need to aid

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[13] SAIDI is the average annual outage duration for each customer, calculated as the sum of all customer interruption durations during a year divided by number of customers served. PGE's 2005 SAIDI was 86 minutes (1.43 hours).

their outage-related inquiries/needs, a gross estimate for the information system support cost will be made.

## IV. Timetable

The table below shows, for each of the initiatives discussed above, net annual benefits, societal benefits, net present value AMI benefits, and the due date for the initiative's implementation plan. The plans will recommend either a test demonstration to validate key benefit/cost assumptions (of a program-level implementation), or an actual program implementation.

One objective in creating the implementation plans will be to improve our estimates of the costs and benefits based on additional research. Actions to be completed in producing each implementation plan include:

- Complete research regarding cost and benefits including, where appropriate, examining other utility programs.
- Outline the specific process changes required to implement a full program, and also the simplified set for the demonstration, if warranted.
- Identify the key assumptions that need to be validated in a demonstration (if one is proposed) to justify moving forward with a full program implementation.
- Produce a benefit/cost analysis for the demonstration, and also for the full program assuming the key demonstration hypotheses hold true.
- Explain risks associated with implementation if any.
- Provide a timeline for completion of major milestones if the initiative were to move forward.
- Present the economic analysis for the initiative, timeline, and a recommendation to proceed, or not, to OPUC by the due date below.

If terms, mutually agreeable to PGE and OPUC, are reached regarding implementation, then PGE will provide within four months, any additional details required to effect a planned implementation.

**Table 1 Estimated Range of Net Benefits**

| Initiative Category | Net Benefits[14] (thousands) | Societal Benefits[15] (thousands) | NPV AMI (millions) | Plan Due Date |
|---|---|---|---|---|
| Demand Response Market Pilot | $0-2,300 | [16] | $0 - 27 | Sept 2007 |
| Appliance Market Transformation | $0-500 | [17] | $0 - 5 | Aug 2007 |
| Info-Driven Energy Savings | $150 - 800 | | $2 - 9 | July 2007 |
| Avoided transformer failure | $30-170 | $10-30 | $0.4 – 2 | June 2007 |
| Deferred Feeder Conductor Work | $40-160 | | $0.4 – 1.6 | Sept 2007 |
| Improved Outage Management | - - Typical Year Benefits - - | | | |
| -Avoided Trouble Calls | $10-30 | | $0.1 – 0.3 | Sept 2007 |
| -Faster One-Premise Response | - | $10-20 | $0.1 – 0.2 | June 2007 |
| -Improved Storm Management | $0-75 | $60-200 | $0 – 0.8 | Sept 2007 |
| -Expedite Fault Location | ($240) [18] | $1,000-3,000 | $9 - 30 | Sept 2007 |
| -Reduced Contact Center Cost | $10 | | ~ $0.1 | June 2007 |

[14] These estimates are assumption-driven with large uncertainty around the number of customers that will actually participate. Some of the scenarios produce negative net benefits.

[15] Dollar amounts listed are based on an average cost to customer during an outage of $15/hour for lost productivity and/or specific losses, e.g. food spoilage.

[16] The benefit would be reduced if the customer incurs incremental costs to purchase controls, e.g., water heater timer, programmable thermostat, etc. to moderate the personal attention required.

[17] If this demonstration were to influence the adoption of a national appliance standard, PGE believes the long term societal benefit would exceed the entire cost of the AMI system multiple times.

[18] Most costs are recovered from the assumed societal benefit; utility benefit alone does not justify installation.

# Attachment 1

Summary NPV

**Customer- and System-Related Benefits**
**Summary NPV**
**($000)**

| Benefit | Low | Normal | High |
|---|---|---|---|
| Demand Response Market Pilot | - | 3,095.6 | 27,404.9 |
| Appliance Market Transformation | - | 1,475.8 | 4,832.3 |
| Info-Driven Energy Savings | 1,611.1 | 4,121.8 | 9,143.2 |
| Avoided transformer failure | 400.0 | 1,200.0 | 2,000.0 |
| Deferred Feeder Conductor Work | 400.0 | 1,117.3 | 1,600.0 |
| Improved Outage Management | | | |
| -Avoided Trouble Calls | 100.0 | 200.0 | 300.0 |
| -Faster One-Premise Response | 100.0 | 150.0 | 200.0 |
| -Improved Storm Management | 18.9 | 334.3 | 859.9 |
| -Expedite Fault Location (a) | 8,620.2 | 20,277.2 | 31,934.2 |
| -Reduced Contact Center Cost | 100.0 | 100.0 | 100.0 |
| **Subtotal NPV - Customer- and System-Related Benefits** | **11,350.2** | **32,072.0** | **78,374.5** |
| **Subtotal without Social Benefits of Expedited Fault Location** | **2,730.0** | **11,794.8** | **46,440.3** |
| **NPV Benefit - AMI Revenue Requirement Analysis (b)** | **33,933.3** | **33,933.3** | **33,933.3** |
| **Total Estimated NPV Benefit** | **36,663.3** | **45,728.1** | **80,373.6** |

Notes:
(a) All social benefits from elimination of customer outages.
(b) See Attachment B to PGE's cost estimates and revenue requirement

# Attachment 2

Analysis of Demand Response Benefits

| **Demmand Response Market Pilot** | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Not Technology aided** | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **NOMINAL SCENARIO** | | | | | | **5.0%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | **100%** | 5,000 | 10,000 | 12,000 | 12,000 | 9,000 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 |
| Customer Attrition | 10% | | -500 | -1,450 | -2,505 | -3,455 | -4,009 | -4,064 | -4,114 | -4,158 | -4,199 | -4,235 | -4,267 | -4,296 | -4,323 |
| Cumlulative Customers | | 5,000 | 14,500 | 25,050 | 34,545 | 40,090 | 40,641 | 41,137 | 41,583 | 41,985 | 42,346 | 42,671 | 42,964 | 43,228 | 43,465 |
| Benefit avg KW | 0.50 | **100%** | **Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | |
| events per year | 20 | | | **0 means remove one-time $ =>** | | | 1 | | Yr 1 & 2 $ | | | | | | |
| Hours per event | 4 | | | | | | | $1,330,000 | $1,330,000 | $0 | **Nom** | | | | |
| Shifted away from peak | 80% | | 20% | is the amount of energy conservation | | | | $1,255,000 | $1,255,000 | $0 | **Low** | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 | avg price off peak according to shift pattern | | | | $1,430,000 | $1,430,000 | $0 | **High** | | | | |
| Avd Capacity $/KW/yr | $ 36 | **100%** | | | | | | | | | | | | | |
| total energy shifted in MWh | | 400 | 1,160 | 2,004 | 2,764 | 3,207 | 3,251 | 3,291 | 3,327 | 3,359 | 3,388 | 3,414 | 3,437 | 3,458 | 3,477 |
| total on-peak KW reduction | | 2,500 | 7,250 | 12,525 | 17,273 | 20,045 | 20,321 | 20,569 | 20,792 | 20,993 | 21,173 | 21,336 | 21,482 | 21,614 | 21,733 |
| Total $ Benefits | | $115,600 | $335,240 | $579,156 | $798,680 | $926,881 | $939,620 | $951,087 | $961,399 | $970,693 | $979,040 | $986,554 | $993,328 | $999,431 | $1,004,911 |
| **Costs** | | avg prgrm cost Yr 2 thru 5 | $556,185 | | | avg prgrm cost post Yr 5 | $435,492 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $20 | $100,000 | $200,000 | $240,000 | $240,000 | $180,000 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $30,000 | $60,000 | $72,000 | $72,000 | $54,000 | $57,360 | $87,360 | $99,360 | $99,360 | $81,360 | $84,720 | $84,720 | $84,720 | $84,720 |
| one Updates per year | $1.00 | $5,000 | $14,500 | $25,050 | $34,545 | $40,090 | $40,641 | $41,137 | $41,583 | $41,985 | $42,346 | $42,671 | $42,964 | $43,228 | $43,465 |
| Critical Pk Notice/event | $0.15 | $15,000 | $43,500 | $75,150 | $103,635 | $120,270 | $121,923 | $123,411 | $124,749 | $125,955 | $127,038 | $128,013 | $128,892 | $129,684 | $130,395 |
| Total $ Costs | $470,000 | $860,000 | $468,000 | $562,200 | $600,180 | $594,360 | $461,124 | $413,108 | $426,892 | $428,500 | $491,944 | $416,604 | $417,776 | $418,832 | $419,780 |
| Net Benefit (loss) | -$470,000 | -$744,400 | -$132,760 | $16,956 | $198,500 | $332,521 | $478,496 | $537,979 | $534,507 | $542,193 | $487,096 | $569,950 | $575,552 | $580,599 | $585,131 |
| Discount Cost of Capital | 5.17% | | | | | -$133,197 | $538,296 | | | | | | | | |
| NPV | 3,095,583 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| | $3,095,583 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 |

**Demmand Response Market Pilot**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Not Technology aided** | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **LOW SCENARIO** | | | | | | **1.5%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | 30% | 1,500 | 3,000 | 3,600 | 3,600 | 2,700 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 |
| Customer Attrition | 10% | | -150 | -435 | -752 | -1,036 | -1,203 | -1,219 | -1,234 | -1,248 | -1,260 | -1,270 | -1,280 | -1,289 | -1,297 |
| Cumlulative Customers | | 1,500 | 4,350 | 7,515 | 10,363 | 12,027 | 12,192 | 12,341 | 12,475 | 12,595 | 12,703 | 12,801 | 12,889 | 12,968 | 13,039 |
| Benefit avg KW | 0.38 | 75% | **Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | |
| events per year | 20 | | | | | | | | | | | | | | |
| Hours per event | 4 | | | | | | | | | | | | | | |
| Shifted away from peak | 80% | | 20% is the amount of energy conservation | | | | | | | | | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 avg price off peak according to shift pattern | | | | | | | | | | | | |
| Avd Capacity $/KW/yr | $ 29 | 80% | | | | | | | | | | | | | |
| total energy shifted in MWh | | 120 | 348 | 601 | 829 | 962 | 975 | 987 | 998 | 1,008 | 1,016 | 1,024 | 1,031 | 1,037 | 1,043 |
| total on-peak KW reduction | | 563 | 1,631 | 2,818 | 3,886 | 4,510 | 4,572 | 4,628 | 4,678 | 4,723 | 4,764 | 4,800 | 4,833 | 4,863 | 4,890 |
| Total $ Benefits | | $23,880 | $69,252 | $119,639 | $164,979 | $191,470 | $194,097 | $196,469 | $198,602 | $200,512 | $202,232 | $203,792 | $205,193 | $206,451 | $207,581 |
| **Costs** | avg prgrm cost Yr 2 thru 5 | | $345,105 | | avg prgrm cost post Yr 5 | | $219,930 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $40 | $60,000 | $120,000 | $144,000 | $144,000 | $108,000 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $9,000 | $18,000 | $21,600 | $21,600 | $16,200 | $17,208 | $26,208 | $29,808 | $29,808 | $24,408 | $25,416 | $25,416 | $25,416 | $25,416 |
| one Updates per year | $1.00 | $1,500 | $4,350 | $7,515 | $10,363 | $12,027 | $12,192 | $12,341 | $12,475 | $12,595 | $12,703 | $12,801 | $12,889 | $12,968 | $13,039 |
| Critical Pk Notice/event | $0.15 | $4,500 | $13,050 | $22,545 | $31,089 | $36,081 | $36,576 | $37,023 | $37,425 | $37,785 | $38,109 | $38,403 | $38,667 | $38,904 | $39,117 |
| Total $ Costs | $470,000 | $785,000 | $305,400 | $345,660 | $357,052 | $372,308 | $270,696 | $200,292 | $204,428 | $204,908 | $279,940 | $201,340 | $201,692 | $202,008 | $202,292 |
| Net Benefit (loss) | -$470,000 | -$761,120 | -$236,148 | -$226,021 | -$192,073 | -$180,838 | -$76,599 | -$3,823 | -$5,826 | -$4,396 | -$77,708 | $2,452 | $3,501 | $4,443 | $5,289 |
| Discount Cost of Capital | 5.17% | | | | | -$344,367 | -$19,745 | | | | | | | | |
| NPV | -2,029,121 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| Levelized | -$2,029,121 | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) |

**Demmand Response Market Pilot**

| **Not Technology aided** | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **HIGH SCENARIO** | | | | | | **10.0%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | **200%** | 10,000 | 20,000 | 24,000 | 24,000 | 18,000 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 |
| Customer Attrition | 10% | | -1,000 | -2,900 | -5,010 | -6,909 | -8,018 | -8,128 | -8,228 | -8,317 | -8,397 | -8,469 | -8,534 | -8,593 | -8,646 |
| Cumlulative Customers | | 10,000 | 29,000 | 50,100 | 69,090 | 80,181 | 81,283 | 82,275 | 83,167 | 83,970 | 84,693 | 85,344 | 85,930 | 86,457 | 86,931 |
| Benefit avg KW | 0.70 | **140%** | **Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | |
| events per year | 20 | | | | | | | | | | | | | | |
| Hours per event | 4 | | | | | | | | | | | | | | |
| Shifted away from peak | 80% | | 20% | is the amount of energy conservation | | | | | | | | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 | avg price off peak according to shift pattern | | | | | | | | | | | |
| Avd Capacity $/KW/yr | $ 58 | **160%** | | | | | | | | | | | | | |
| total energy shifted in MWh | | 800 | 2,320 | 4,008 | 5,527 | 6,414 | 6,503 | 6,582 | 6,653 | 6,718 | 6,775 | 6,828 | 6,874 | 6,917 | 6,954 |
| total on-peak KW reduction | | 7,000 | 20,300 | 35,070 | 48,363 | 56,127 | 56,898 | 57,593 | 58,217 | 58,779 | 59,285 | 59,741 | 60,151 | 60,520 | 60,852 |
| Total $ Benefits | | $454,400 | $1,317,760 | $2,276,544 | $3,139,450 | $3,643,425 | $3,693,500 | $3,738,576 | $3,779,108 | $3,815,597 | $3,848,450 | $3,878,031 | $3,904,659 | $3,928,606 | $3,950,145 |
| **Costs** | | avg prgrm cost Yr 2 thru 5 | $842,371 | | | avg prgrm cost post Yr 5 | $736,928 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $15 | $150,000 | $300,000 | $360,000 | $360,000 | $270,000 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $60,000 | $120,000 | $144,000 | $144,000 | $108,000 | $114,720 | $174,720 | $198,720 | $198,720 | $162,720 | $169,440 | $169,440 | $169,440 | $169,440 |
| one Updates per year | $1.00 | $10,000 | $29,000 | $50,100 | $69,090 | $80,181 | $81,283 | $82,275 | $83,167 | $83,970 | $84,693 | $85,344 | $85,930 | $86,457 | $86,931 |
| Critical Pk Notice/event | $0.15 | $30,000 | $87,000 | $150,300 | $207,270 | $240,543 | $243,849 | $246,825 | $249,501 | $251,910 | $254,079 | $256,032 | $257,790 | $259,371 | $260,793 |
| Total $ Costs | $470,000 | $960,000 | $686,000 | $854,400 | $930,360 | $898,724 | $726,652 | $710,620 | $738,188 | $741,400 | $788,292 | $717,616 | $719,960 | $722,068 | $723,964 |
| Net Benefit (loss) | -$470,000 | -$505,600 | $631,760 | $1,422,144 | $2,209,090 | $2,744,701 | $2,966,848 | $3,027,956 | $3,040,920 | $3,074,197 | $3,060,158 | $3,160,415 | $3,184,699 | $3,206,538 | $3,226,181 |
| Discount Cost of Capital | 5.17% | | | | | $1,005,349 | $3,090,216 | | | | | | | | |
| NPV | 27,404,898 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| | $27,404,898 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 |

| Demmand Response Market Pilot | | | | | |
|---|---|---|---|---|---|
| **Not Technology aided** | | Year 15 | Year 16 | Year 17 | Year 18 |
| Targeted to SF & MF | | 2023 | 2024 | 2025 | 2026 |
| **NOMINAL SCENARIO** | | | | | |
| New Incremental Customers | | 4,560 | 4,560 | 4,560 | 4,560 |
| Customer Attrition | | -4,347 | -4,368 | -4,387 | -4,404 |
| Cumlulative Customers | | 43,678 | 43,870 | 44,043 | 44,199 |
| | Benefit avg KW | | | | |
| | events per year | | | | |
| | Hours per event | | | | |
| | Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | | |
| Avd Capacity $/KW/yr | | | | | |
| total energy shifted in MWh | | 3,494 | 3,510 | 3,523 | 3,536 |
| total on-peak KW reduction | | 21,839 | 21,935 | 22,022 | 22,100 |
| | Total $ Benefits | $1,009,835 | $1,014,274 | $1,018,274 | $1,021,881 |
| **Costs** | | | | | |
| Program Management | | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | | $91,200 | $91,200 | $91,200 | $91,200 |
| Educational every 5 yrs | | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | | $84,720 | $84,720 | $84,720 | $84,720 |
| one Updates per year | | $43,678 | $43,870 | $44,043 | $44,199 |
| Critical Pk Notice/event | | $131,034 | $131,610 | $132,129 | $132,597 |
| | Total $ Costs | $500,632 | $421,400 | $422,092 | $422,716 |
| Net Benefit (loss) | | $509,203 | $592,874 | $596,182 | $599,165 |
| | Discount Cost of Capital | | | | |
| | NPV | | | | |
| | | $268,344 | $268,344 | $268,344 | $268,344 |

| Demmand Response Market Pilot | Year 15 | Year 16 | Year 17 | Year 18 |
|---|---|---|---|---|
| **Not Technology aided** | | | | |
| Targeted to SF & MF | 2023 | 2024 | 2025 | 2026 |
| **LOW SCENARIO** | | | | |
| New Incremental Customers | 1,368 | 1,368 | 1,368 | 1,368 |
| Customer Attrition | -1,304 | -1,310 | -1,316 | -1,321 |
| Cumlulative Customers | 13,103 | 13,161 | 13,213 | 13,260 |
| Benefit avg KW | | | | |
| events per year | | | | |
| Hours per event | | | | |
| Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | |
| Avd Capacity $/KW/yr | | | | |
| total energy shifted in MWh | 1,048 | 1,053 | 1,057 | 1,061 |
| total on-peak KW reduction | 4,914 | 4,935 | 4,955 | 4,973 |
| Total $ Benefits | $208,600 | $209,523 | $210,351 | $211,099 |
| **Costs** | | | | |
| Program Management | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $54,720 | $54,720 | $54,720 | $54,720 |
| Educational every 5 yrs | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $25,416 | $25,416 | $25,416 | $25,416 |
| one Updates per year | $13,103 | $13,161 | $13,213 | $13,260 |
| Critical Pk Notice/event | $39,309 | $39,483 | $39,639 | $39,780 |
| Total $ Costs | $282,548 | $202,780 | $202,988 | $203,176 |
| Net Benefit (loss) | -$73,948 | $6,743 | $7,363 | $7,923 |
| Discount Cost of Capital | | | | |
| NPV | | | | |
| Levelized | ($175,897) | ($175,897) | ($175,897) | ($175,897) |

| | | Year 15 | Year 16 | Year 17 | Year 18 |
|---|---|---|---|---|---|
| **Demmand Response Market Pilot** | | | | | |
| **Not Technology aided** | | Year 15 | Year 16 | Year 17 | Year 18 |
| Targeted to SF & MF | | 2023 | 2024 | 2025 | 2026 |
| **HIGH SCENARIO** | | | | | |
| New Incremental Customers | | 9,120 | 9,120 | 9,120 | 9,120 |
| Customer Attrition | | -8,693 | -8,736 | -8,774 | -8,809 |
| Cumlulative Customers | | 87,358 | 87,742 | 88,088 | 88,399 |
| Benefit | avg KW | | | | |
| | events per year | | | | |
| | Hours per event | | | | |
| | Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | | |
| Avd Capacity $/KW/yr | | | | | |
| total energy shifted in MWh | | 6,989 | 7,019 | 7,047 | 7,072 |
| total on-peak KW reduction | | 61,151 | 61,419 | 61,662 | 61,879 |
| | Total $ Benefits | $3,969,548 | $3,986,996 | $4,002,719 | $4,016,851 |
| **Costs** | | | | | |
| Program Management | | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | | $136,800 | $136,800 | $136,800 | $136,800 |
| Educational every 5 yrs | | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | | $169,440 | $169,440 | $169,440 | $169,440 |
| one Updates per year | | $87,358 | $87,742 | $88,088 | $88,399 |
| Critical Pk Notice/event | | $262,074 | $263,226 | $264,264 | $265,197 |
| | Total $ Costs | $805,672 | $727,208 | $728,592 | $729,836 |
| Net Benefit (loss) | | $3,163,876 | $3,259,788 | $3,274,127 | $3,287,015 |
| | Discount Cost of Capital | | | | |
| | NPV | $2,375,624 | $2,375,624 | $2,375,624 | ######### |

**Customer- and System-Related Benefits**
**Summary NPV**
**($000)**

| Benefit | Low | Normal | High |
|---|---|---|---|
| Demand Response Market Pilot | - | 3,095.6 | 27,404.9 |
| Appliance Market Transformation | - | 1,475.8 | 4,832.3 |
| Info-Driven Energy Savings | 1,611.1 | 4,121.8 | 9,143.2 |
| Avoided transformer failure | 400.0 | 1,200.0 | 2,000.0 |
| Deferred Feeder Conductor Work | 400.0 | 1,117.3 | 1,600.0 |
| Improved Outage Management | | | |
| -Avoided Trouble Calls | 100.0 | 200.0 | 300.0 |
| -Faster One-Premise Response | 100.0 | 150.0 | 200.0 |
| -Improved Storm Management | 18.9 | 334.3 | 859.9 |
| -Expedite Fault Location (a) | 8,620.2 | 20,277.2 | 31,934.2 |
| -Reduced Contact Center Cost | 100.0 | 100.0 | 100.0 |
| **Subtotal NPV - Customer- and System-Related Benefits** | **11,350.2** | **32,072.0** | **78,374.5** |
| **Subtotal without Social Benefits of Expedited Fault Location** | **2,730.0** | **11,794.8** | **46,440.3** |
| **NPV Benefit - AMI Revenue Requirement Analysis (b)** | **33,933.3** | **33,933.3** | **33,933.3** |
| **Total Estimated NPV Benefit** | **36,663.3** | **45,728.1** | **80,373.6** |

Notes:
(a) All social benefits from elimination of customer outages.
(b) See Attachment B to PGE's cost estimates and revenue requirement

| | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demmand Response Market Pilot** | | | | | | | | | | | | | | | |
| **Not Technology aided** | | | | | | | | | | | | | | | |
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **NOMINAL SCENARIO** | | | | | | **5.0%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | 100% | 5,000 | 10,000 | 12,000 | 12,000 | 9,000 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 | 4,560 |
| Customer Attrition | 10% | | -500 | -1,450 | -2,505 | -3,455 | -4,009 | -4,064 | -4,114 | -4,158 | -4,199 | -4,235 | -4,267 | -4,296 | -4,323 |
| Cumlulative Customers | | 5,000 | 14,500 | 25,050 | 34,545 | 40,090 | 40,641 | 41,137 | 41,583 | 41,985 | 42,346 | 42,671 | 42,964 | 43,228 | 43,465 |
| Benefit avg KW | 0.50 | **100% Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | | |
| events per year | 20 | | | **0 means remove one-time $ =>** | | | **1** | | Yr 1 & 2 $ | | | | | | |
| Hours per event | 4 | | | | | | | $1,330,000 | $1,330,000 | $0 | **Nom** | | | | |
| Shifted away from peak | 80% | | 20% is the amount of energy conservation | | | | | $1,255,000 | $1,255,000 | $0 | **Low** | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 | avg price off peak according to shift pattern | | | | $1,430,000 | $1,430,000 | $0 | **High** | | | | |
| Avd Capacity $/KW/yr | $ 36 | **100%** | | | | | | | | | | | | | |
| total energy shifted in MWh | | 400 | 1,160 | 2,004 | 2,764 | 3,207 | 3,251 | 3,291 | 3,327 | 3,359 | 3,388 | 3,414 | 3,437 | 3,458 | 3,477 |
| total on-peak KW reduction | | 2,500 | 7,250 | 12,525 | 17,273 | 20,045 | 20,321 | 20,569 | 20,792 | 20,993 | 21,173 | 21,336 | 21,482 | 21,614 | 21,733 |
| Total $ Benefits | | $115,600 | $335,240 | $579,156 | $798,680 | $926,881 | $939,620 | $951,087 | $961,399 | $970,693 | $979,040 | $986,554 | $993,328 | $999,431 | $1,004,911 |
| **Costs** | avg prgrm cost Yr 2 thru 5 | | $556,185 | | avg prgrm cost post Yr 5 | | $435,492 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $20 | $100,000 | $200,000 | $240,000 | $240,000 | $180,000 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 | $91,200 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $30,000 | $60,000 | $72,000 | $72,000 | $54,000 | $57,360 | $87,360 | $99,360 | $99,360 | $81,360 | $84,720 | $84,720 | $84,720 | $84,720 |
| one Updates per year | $1.00 | $5,000 | $14,500 | $25,050 | $34,545 | $40,090 | $40,641 | $41,137 | $41,583 | $41,985 | $42,346 | $42,671 | $42,964 | $43,228 | $43,465 |
| Critical Pk Notice/event | $0.15 | $15,000 | $43,500 | $75,150 | $103,635 | $120,270 | $121,923 | $123,411 | $124,749 | $125,955 | $127,038 | $128,013 | $128,892 | $129,684 | $130,395 |
| Total $ Costs | $470,000 | $860,000 | $468,000 | $562,200 | $600,180 | $594,360 | $461,124 | $413,108 | $426,892 | $428,500 | $491,944 | $416,604 | $417,776 | $418,832 | $419,780 |
| Net Benefit (loss) | -$470,000 | -$744,400 | -$132,760 | $16,956 | $198,500 | $332,521 | $478,496 | $537,979 | $534,507 | $542,193 | $487,096 | $569,950 | $575,552 | $580,599 | $585,131 |
| Discount Cost of Capital | 5.17% | | | | | -$133,197 | $538,296 | | | | | | | | |
| NPV | 3,095,583 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| | $3,095,583 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 | $268,344 |

| | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demmand Response Market Pilot** | | | | | | | | | | | | | | | |
| **Not Technology aided** | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **LOW SCENARIO** | | | | | | **1.5%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | 30% | 1,500 | 3,000 | 3,600 | 3,600 | 2,700 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 | 1,368 |
| Customer Attrition | 10% | | -150 | -435 | -752 | -1,036 | -1,203 | -1,219 | -1,234 | -1,248 | -1,260 | -1,270 | -1,280 | -1,289 | -1,297 |
| Cumlulative Customers | | 1,500 | 4,350 | 7,515 | 10,363 | 12,027 | 12,192 | 12,341 | 12,475 | 12,595 | 12,703 | 12,801 | 12,889 | 12,968 | 13,039 |
| Benefit avg KW | 0.38 | 75% | **Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | |
| events per year | 20 | | | | | | | | | | | | | | |
| Hours per event | 4 | | | | | | | | | | | | | | |
| Shifted away from peak | 80% | | 20% | is the amount of energy conservation | | | | | | | | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 | avg price off peak according to shift pattern | | | | | | | | | | | |
| Avd Capacity $/KW/yr | $ 29 | 80% | | | | | | | | | | | | | |
| total energy shifted in MWh | | 120 | 348 | 601 | 829 | 962 | 975 | 987 | 998 | 1,008 | 1,016 | 1,024 | 1,031 | 1,037 | 1,043 |
| total on-peak KW reduction | | 563 | 1,631 | 2,818 | 3,886 | 4,510 | 4,572 | 4,628 | 4,678 | 4,723 | 4,764 | 4,800 | 4,833 | 4,863 | 4,890 |
| Total $ Benefits | | $23,880 | $69,252 | $119,639 | $164,979 | $191,470 | $194,097 | $196,469 | $198,602 | $200,512 | $202,232 | $203,792 | $205,193 | $206,451 | $207,581 |
| **Costs** | | avg prgrm cost Yr 2 thru 5 | $345,105 | | | avg prgrm cost post Yr 5 | $219,930 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $40 | $60,000 | $120,000 | $144,000 | $144,000 | $108,000 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 | $54,720 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $9,000 | $18,000 | $21,600 | $21,600 | $16,200 | $17,208 | $26,208 | $29,808 | $29,808 | $24,408 | $25,416 | $25,416 | $25,416 | $25,416 |
| one Updates per year | $1.00 | $1,500 | $4,350 | $7,515 | $10,363 | $12,027 | $12,192 | $12,341 | $12,475 | $12,595 | $12,703 | $12,801 | $12,889 | $12,968 | $13,039 |
| Critical Pk Notice/event | $0.15 | $4,500 | $13,050 | $22,545 | $31,089 | $36,081 | $36,576 | $37,023 | $37,425 | $37,785 | $38,109 | $38,403 | $38,667 | $38,904 | $39,117 |
| Total $ Costs | $470,000 | $785,000 | $305,400 | $345,660 | $357,052 | $372,308 | $270,696 | $200,292 | $204,428 | $204,908 | $279,940 | $201,340 | $201,692 | $202,008 | $202,292 |
| Net Benefit (loss) | -$470,000 | -$761,120 | -$236,148 | -$226,021 | -$192,073 | -$180,838 | -$76,599 | -$3,823 | -$5,826 | -$4,396 | -$77,708 | $2,452 | $3,501 | $4,443 | $5,289 |
| Discount Cost of Capital | 5.17% | | | | | -$344,367 | -$19,745 | | | | | | | | |
| NPV | -2,029,121 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| Levelized | -$2,029,121 | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) | ($175,897) |

| **Demmand Response Market Pilot** | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Not Technology aided** | Prep | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 |
| Targeted to SF & MF | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| **HIGH SCENARIO** | | | | | | **10.0%** | **<=Penetration at end of 5 years** | | | | | | | | |
| New Incremental Customers | 200% | 10,000 | 20,000 | 24,000 | 24,000 | 18,000 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 | 9,120 |
| Customer Attrition | 10% | | -1,000 | -2,900 | -5,010 | -6,909 | -8,018 | -8,128 | -8,228 | -8,317 | -8,397 | -8,469 | -8,534 | -8,593 | -8,646 |
| Cumlulative Customers | | 10,000 | 29,000 | 50,100 | 69,090 | 80,181 | 81,283 | 82,275 | 83,167 | 83,970 | 84,693 | 85,344 | 85,930 | 86,457 | 86,931 |
| Benefit avg KW | 0.70 | 140% | **Values in red show percentage of Nominal Value for Sensitivity Analysis** | | | | | | | | | | | | |
| events per year | 20 | | | | | | | | | | | | | | |
| Hours per event | 4 | | | | | | | | | | | | | | |
| Shifted away from peak | 80% | | 20% is the amount of energy conservation | | | | | | | | | | | | |
| Avd Energy $/MWh | $100.00 | on peak | $45.00 avg price off peak according to shift pattern | | | | | | | | | | | | |
| Avd Capacity $/KW/yr | $ 58 | 160% | | | | | | | | | | | | | |
| total energy shifted in MWh | | 800 | 2,320 | 4,008 | 5,527 | 6,414 | 6,503 | 6,582 | 6,653 | 6,718 | 6,775 | 6,828 | 6,874 | 6,917 | 6,954 |
| total on-peak KW reduction | | 7,000 | 20,300 | 35,070 | 48,363 | 56,127 | 56,898 | 57,593 | 58,217 | 58,779 | 59,285 | 59,741 | 60,151 | 60,520 | 60,852 |
| Total $ Benefits | | $454,400 | $1,317,760 | $2,276,544 | $3,139,450 | $3,643,425 | $3,693,500 | $3,738,576 | $3,779,108 | $3,815,597 | $3,848,450 | $3,878,031 | $3,904,659 | $3,928,606 | $3,950,145 |
| **Costs** | avg prgrm cost Yr 2 thru 5 | | $842,371 | | avg prgrm cost post Yr 5 | | $736,928 | | | | | | | | |
| Program Management | $130,000 | $130,000 | $130,000 | $130,000 | $130,000 | $100,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $300,000 | $500,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $15 | $150,000 | $300,000 | $360,000 | $360,000 | $270,000 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 | $136,800 |
| Educational every 5 yrs | $40,000 | $80,000 | $20,000 | $20,000 | $20,000 | $100,000 | $100,000 | $20,000 | $20,000 | $20,000 | $100,000 | $20,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $6.00 | $60,000 | $120,000 | $144,000 | $144,000 | $108,000 | $114,720 | $174,720 | $198,720 | $198,720 | $162,720 | $169,440 | $169,440 | $169,440 | $169,440 |
| one Updates per year | $1.00 | $10,000 | $29,000 | $50,100 | $69,090 | $80,181 | $81,283 | $82,275 | $83,167 | $83,970 | $84,693 | $85,344 | $85,930 | $86,457 | $86,931 |
| Critical Pk Notice/event | $0.15 | $30,000 | $87,000 | $150,300 | $207,270 | $240,543 | $243,849 | $246,825 | $249,501 | $251,910 | $254,079 | $256,032 | $257,790 | $259,371 | $260,793 |
| Total $ Costs | $470,000 | $960,000 | $686,000 | $854,400 | $930,360 | $898,724 | $726,652 | $710,620 | $738,188 | $741,400 | $788,292 | $717,616 | $719,960 | $722,068 | $723,964 |
| Net Benefit (loss) | -$470,000 | -$505,600 | $631,760 | $1,422,144 | $2,209,090 | $2,744,701 | $2,966,848 | $3,027,956 | $3,040,920 | $3,074,197 | $3,060,158 | $3,160,415 | $3,184,699 | $3,206,538 | $3,226,181 |
| Discount Cost of Capital | 5.17% | | | | | $1,005,349 | $3,090,216 | | | | | | | | |
| NPV | 27,404,898 | | **Typical Year Benefit, i.e. levelized** | | | | | | | | | | | | |
| | $27,404,898 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 | $2,375,624 |

| | | Year 15 | Year 16 | Year 17 | Year 18 |
|---|---|---|---|---|---|
| **Demmand Response Market Pilot** | | | | | |
| **Not Technology aided** | | Year 15 | Year 16 | Year 17 | Year 18 |
| Targeted to SF & MF | | 2023 | 2024 | 2025 | 2026 |
| **NOMINAL SCENARIO** | | | | | |
| New Incremental Customers | | 4,560 | 4,560 | 4,560 | 4,560 |
| Customer Attrition | | -4,347 | -4,368 | -4,387 | -4,404 |
| Cumlulative Customers | | 43,678 | 43,870 | 44,043 | 44,199 |
| | Benefit avg KW | | | | |
| | events per year | | | | |
| | Hours per event | | | | |
| | Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | | |
| Avd Capacity $/KW/yr | | | | | |
| total energy shifted in MWh | | 3,494 | 3,510 | 3,523 | 3,536 |
| total on-peak KW reduction | | 21,839 | 21,935 | 22,022 | 22,100 |
| | Total $ Benefits | $1,009,835 | $1,014,274 | $1,018,274 | $1,021,881 |
| **Costs** | | | | | |
| Program Management | | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | | $91,200 | $91,200 | $91,200 | $91,200 |
| Educational every 5 yrs | | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | | $84,720 | $84,720 | $84,720 | $84,720 |
| one Updates per year | | $43,678 | $43,870 | $44,043 | $44,199 |
| Critical Pk Notice/event | | $131,034 | $131,610 | $132,129 | $132,597 |
| | Total $ Costs | $500,632 | $421,400 | $422,092 | $422,716 |
| Net Benefit (loss) | | $509,203 | $592,874 | $596,182 | $599,165 |
| | Discount Cost of Capital | | | | |
| | NPV | $268,344 | $268,344 | $268,344 | $268,344 |

| **Demmand Response Market Pilot** | | | | |
|---|---|---|---|---|
| **Not Technology aided** | Year 15 | Year 16 | Year 17 | Year 18 |
| Targeted to SF & MF | 2023 | 2024 | 2025 | 2026 |
| **LOW SCENARIO** | | | | |
| New Incremental Customers | 1,368 | 1,368 | 1,368 | 1,368 |
| Customer Attrition | -1,304 | -1,310 | -1,316 | -1,321 |
| Cumlulative Customers | 13,103 | 13,161 | 13,213 | 13,260 |
| Benefit avg KW | | | | |
| events per year | | | | |
| Hours per event | | | | |
| Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | |
| Avd Capacity $/KW/yr | | | | |
| total energy shifted in MWh | 1,048 | 1,053 | 1,057 | 1,061 |
| total on-peak KW reduction | 4,914 | 4,935 | 4,955 | 4,973 |
| Total $ Benefits | $208,600 | $209,523 | $210,351 | $211,099 |
| **Costs** | | | | |
| Program Management | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | $54,720 | $54,720 | $54,720 | $54,720 |
| Educational every 5 yrs | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | $25,416 | $25,416 | $25,416 | $25,416 |
| one Updates per year | $13,103 | $13,161 | $13,213 | $13,260 |
| Critical Pk Notice/event | $39,309 | $39,483 | $39,639 | $39,780 |
| Total $ Costs | $282,548 | $202,780 | $202,988 | $203,176 |
| Net Benefit (loss) | -$73,948 | $6,743 | $7,363 | $7,923 |
| Discount Cost of Capital | | | | |
| NPV | | | | |
| Levelized | ($175,897) | ($175,897) | ($175,897) | ($175,897) |

| | | Year 15 | Year 16 | Year 17 | Year 18 |
|---|---|---|---|---|---|
| **Demmand Response Market Pilot** | | | | | |
| **Not Technology aided** | | Year 15 | Year 16 | Year 17 | Year 18 |
| Targeted to SF & MF | | 2023 | 2024 | 2025 | 2026 |
| **HIGH SCENARIO** | | | | | |
| New Incremental Customers | | 9,120 | 9,120 | 9,120 | 9,120 |
| Customer Attrition | | -8,693 | -8,736 | -8,774 | -8,809 |
| Cumlulative Customers | | 87,358 | 87,742 | 88,088 | 88,399 |
| Benefit | avg KW | | | | |
| | events per year | | | | |
| | Hours per event | | | | |
| | Shifted away from peak | | | | |
| Avd Energy $/MWh | | | | | |
| Avd Capacity $/KW/yr | | | | | |
| total energy shifted in MWh | | 6,989 | 7,019 | 7,047 | 7,072 |
| total on-peak KW reduction | | 61,151 | 61,419 | 61,662 | 61,879 |
| | Total $ Benefits | $3,969,548 | $3,986,996 | $4,002,719 | $4,016,851 |
| **Costs** | | | | | |
| Program Management | | $50,000 | $50,000 | $50,000 | $50,000 |
| System Development | | $0 | $0 | $0 | $0 |
| Promotion per enrolled customer | | $136,800 | $136,800 | $136,800 | $136,800 |
| Educational every 5 yrs | | $100,000 | $20,000 | $20,000 | $20,000 |
| Print/Mail cost each | | $169,440 | $169,440 | $169,440 | $169,440 |
| one Updates per year | | $87,358 | $87,742 | $88,088 | $88,399 |
| Critical Pk Notice/event | | $262,074 | $263,226 | $264,264 | $265,197 |
| | Total $ Costs | $805,672 | $727,208 | $728,592 | $729,836 |
| Net Benefit (loss) | | $3,163,876 | $3,259,788 | $3,274,127 | $3,287,015 |
| | Discount Cost of Capital | | | | |
| | NPV | | | | |
| | | $2,375,624 | $2,375,624 | $2,375,624 | ######### |