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

September 4, 2009

via E-Filing and US Mail

Public Utility Commission of Oregon
550 Capitol St., NE, No.215
Salem, OR 97308-2148

Attention: **Commission Filing Center**:

Re: **UM___** Application for Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects

Enclosed are an original and one copy of Portland General Electric Company's application for deferred accounting of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects. Also enclosed, are PGE Work Papers supporting the application.

Notice of Application for Deferred Accounting of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects has been forwarded to the UE-197 service list. This document is being filed by electronic mail with the Filing Center.

Thank you for your assistance in this matter. If you have any questions or require further information, please call me at (503) 464-7580 or Alex Tooman at (503) 464-7623.

Please direct all formal correspondence, questions, or requests to the following e-mail address pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

Encls.

PGH/jmb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM ____

In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects	**Application for Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects**

Pursuant to ORS 757.259 and OAR 860-027-0300, Portland General Electric Company ("PGE") hereby requests authorization to defer for later ratemaking treatment costs and benefits associated with the projects for which PGE has filed Smart Grid Investment Grant (SGIG) application with the U.S. Department of Energy (USDOE). This filing is being made to initiate the required deferral that will support an automatic adjustment clause rate schedule. PGE will submit the new rate schedule shortly after this application. The deferral as set out in this application and the rate schedule are contingent on USDOE approval of PGE's grant applications. The automatic adjustment clause entails deferring the revenue requirement of approved stimulus projects for costs incurred and grant funding received during 2009 and 2010. The deferral would then be amortized under the new rate schedule in 2011 and/or 2012 subject to a prudence review. PGE will include all stimulus project costs incurred after December 31, 2010 in subsequent rate proceedings (e.g., a 2011 test year general rate case). In support of this Application, PGE states:

1. PGE is a public utility in the state of Oregon and its rates, services and accounting practices are subject to the regulation of the Commission.
2. This application is filed pursuant to ORS 757.259, which allows the Commission, upon application, to authorize deferral of certain items for later incorporation in rates.
3. Communications regarding this Application should be addressed to:

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PGE waives paper service in this proceeding. In addition to the names and addresses above, the following are to receive notices and communications via the e-mail service list:

Patrick G. Hager, Manager, Regulatory Affairs
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I. OAR 860-027-0300(3) Requirements

A. Background

On February 17, 2009, President Barack Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA), which provided a nominal amount of $787 billion (stimulus funds) for federal tax relief, expansion of unemployment benefits and other social welfare provisions, and domestic spending in education, health care, and infrastructure, including the energy sector. ARRA funding for the energy sector is administered by the USDOE and is intended to support projects that will help to preserve and create jobs, promote economic recovery, increase economic efficiency, and provide long-term economic benefits. On average, the funding is intended to cover approximately half of the capital and one-time costs associated with approved projects.

On August 6, 2009, PGE filed a Smart Grid Investment Grant application with the USDOE for four projects that potentially qualify for stimulus funds and are in the interest of PGE's customers. These projects consist of:

- Advanced Metering Infrastructure (AMI) system as approved by Commission Order

08-245 (Docket No. UE 189); estimated deferral of approximately ($10.2 million) credit over 2009 and 2010.

- Real-Time Processing and Response program that enables PGE and customers to fully realize customer and system benefits utilizing data from the AMI system; estimated deferral of approximately $131,000 in 2010.
- Secure Energy Network, which is a cyber security project that PGE must complete in order to comply with recent NERC requirements; estimated deferral of approximately $302,000 over 2009 and 2010.
- Distribution Technology (DT), which will replace PGE's Distribution Geographic Information System (GIS) and Outage Management System (OMS) with leading technologies that maximize utilization of smart devices. DT will also enable mobility of the GIS and OMS for field use by expanding implementation of mobile devices and upgrading to a Mobile Workforce Management (MWM) system; estimated deferral of approximately $800,000 in 2010.

Each of these projects is described in more detail below.

<u>AMI</u>

PGE is currently installing an AMI system that enables the automated collection of meter data via a fixed network. The complete AMI system will consist of solid-state electronic meters, a communication system or network to transmit the data, and a communication server or computer system that receives and stores data from the meter. As a two-way system, AMI enables PGE to send commands to the meter or control devices at the customers' premises. Based on Commission approval in Order No. 08-245, PGE began system acceptance testing (SAT) on June 1, 2008. PGE successfully completed SAT on April 10, 2009, after which we began full deployment of the AMI system. Because the incremental impact of AMI is only from SGIG funding, the amounts to be deferred represent credits to be refunded to customers.

Real-Time Processing and Response Program

This project will create a "sense and respond" system that will: 1) provide facilities for sensing real-time and interval data feeds from multiple sources – including AMI; 2) process that data in near real-time to identify business patterns; 3) display the pattern results and aggregate data measures in a dashboard format; and 4) trigger action in appropriate business functions based upon the patterns identified. The project is divided into two phases. The first phase, which will last eight to 12 months, is intended to prove that the "sense and respond" concept works and that the selected technology is appropriate for that purpose. The second phase extends the technology used in the first phase in preparation for production and testing purposes and will last until the end of 2010.

If implemented, the Real-Time Processing system is projected to be the primary component needed to achieve several customer and system benefits that PGE identified with respect to its AMI system (which we committed to explore per the Conditions document adopted by Commission Order No. 08-245, Appendix A, pages 10-21). Exhibit B to this filing summarizes these specific benefits, which were initially provided as PGE Exhibit 103 in Docket No. UE 189.

Secure Energy Network

The Secure Energy Network project implements a network dedicated to the protection of critical cyber assets that fall under the guidance of the new Critical Infrastructure Protection (CIP) standards as developed by the North American Reliability Corporation (NERC). These extensive standards have the force of law by authority of the Federal Energy Regulatory Commission (FERC), and can be enforced with fines of up to $1 million per day for utilities found to be not in compliance. More specifically, PGE's technologies associated with critical assets require a stringent level of control and protection, which means they must be separated from the PGE's Corporate Local Area Network (LAN – the system that encompasses PGE's other communication and data systems). This project allows PGE to further protect critical cyber assets that support crucial business functions related to the reliability of the bulk electric system. An additional benefit of this system is compliance with NERC requirements and avoided fines for non-compliance.

Distribution Technology

As noted above, PGE plans to replace our GIS and OMS systems and upgrade to a MWM system. Our current OMS system is outdated and not designed to utilize data from smart devices like smart meters and PGE's SCADA system. In addition, the in-house developed OMS is nearing obsolescence because it is written in a computer language (Microsoft Visual Basic 6 or VB6) that will be unsupported by Microsoft in a few years. PGE's current GIS[1] is also nearing obsolescence because it is not designed to maintain all data required by a contemporary OMS. It is also becoming very difficult to find qualified IT expertise to operate and maintain the current GIS. Further, components of GIS use VB6 code, similar to the current OMS. Finally, PGE's current mobile workforce system (ServiceLink) and hardware cannot provide operations and customer benefits at a level available through new GIS, OMS, and Enterprise Asset Management (EAM) technologies.

B. Reasons for Deferral

PGE seeks deferred accounting treatment for the net of incremental costs and SGIG funds associated with the above listed projects based on PGE's proposed stimulus projects adjustment clause rate schedule (to be filed after this application) that is structured similar to the Company's Renewable Resources Automatic Adjustment Clause (RAC), Schedule 122. This process allows for recovery of prudently incurred costs plus a deferral of costs prior to inclusion in rates. In short, because of the special nature of these particular projects, a RAC-type deferral and cost recovery process provides PGE with both the regulatory approval needed to receive ARRA funding and incorporate the costs/funds into retail rates. Based on the special nature of these projects and related funding, PGE

[1] The GIS is the data source of the OMS connectivity model.

requests that the Commission issue an order that approves PGE's proposed stimulus automatic adjustment clause and associated deferral, contingent on USDOE approval of PGE's grant application. PGE also requests that the Commission Order be issued before the end of October 2009 so that it can precede or coincide with the USDOE's decision regarding PGE's grant application. The Commission's initial support for these stimulus projects (a letter to the USDOE) is Exhibit C.

Consistent with the new rate schedule, which PGE will submit shortly after this application, the SGIG projects' costs include all fixed costs, operation and maintenance expenses, income taxes, property taxes, and other applicable fees and costs. If SGIG funding is approved for AMI, however, the new rate schedule will entail a refund to customers.

The granting of this Application will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers. Approving the Application will not authorize a change in rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding.

C. Proposed Accounting

PGE proposes to record the deferred amount as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Electric Revenue. In the absence of a deferred accounting order from the Commission, PGE would record costs to several different FERC accounts, including FERC account 921, Office Supplies and Expenses, FERC account 403.1, Depreciation Expense, etc.

D. Estimate of Amounts

The proposed deferral will be used to accumulate the revenue requirement of all costs associated with the SGIG projects,[2] as they are incurred between the deferral filing date in 2009 until

[2] For AMI, only the benefits of the SGIG grant are included in the deferral since the costs are being recovered through Tariff Schedule 111 during the deployment period of June 1, 2008 through December 31, 2010.

December 31, 2011, subject to OPUC regulatory approval and USDOE grant approval. Ideally, if PGE receives full SGIG funding for all the proposed projects, the deferral will create a liability to be refunded to customers. This is because the incremental impact from AMI would be the largest component of the deferral and is based solely on the SGIG funds that would reduce the project's overall costs. Details for the proposed cost and fund impacts are provided in Exhibit A, which assumes full SGIG funding for all four projects. Based on this assumed level of costs and SGIG funds, PGE estimates the amount subject to the deferral would be approximately ($9.0 million) credit (see work papers for detail).

E. Notice

A copy of the notice of application for deferred accounting treatment and a list of persons served with the notice are attached to the Application as Attachment A.

F. Schedule

Relative to the four smart grid projects, PGE expects to make filings similar to those made in a RAC filing pursuant to ORS 469A.120 and Commission Order No. 07-572. First, PGE is making this request for authorization to defer for later rate-making treatment the first year costs and SGIG funding. Second, PGE will request re-authorization for the deferral of costs and funds to be incurred in subsequent years, ending no later than December 31, 2011. We also expect to file a tariff seeking inclusion into rates. This will be effective on January 1, 2011 and/or 2012 for those projects that are in-service as well as amortization of the deferred amounts. Both the number of years required for deferrals and rate recovery will depend on which, if any projects receive SGIG funding.

II. Conclusion

For the reasons stated above, PGE requests permission to defer the net incremental costs and benefits of SGIG funding associated with the real-time processing and response program, secure energy network, distribution technology, and AMI as described herein from the date of this Application.

Dated this September 4, 2009.

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Exhibit A

Estimated Cost and SGIG Fund Impacts

PGE's Smart Grid Investment Grant Projects
Summary of Estimated Costs by Project by Type by Year

	2009	2010	2011	Totals
Capital				
Secure Energy Network				
Software	-	155,187	-	155,187
Hardware	382,773	-	-	382,773
Total Secure Energy Network	**382,773**	**155,187**	**-**	**537,959**
Real Time Processing				
Software	-	-	1,142,185	1,142,185
Hardware	-	285,000	242,500	527,500
Total Real Time Processing	**-**	**285,000**	**1,384,685**	**1,669,685**
AMI				
Software	(1,867,058)	(4,362,560)	-	(6,229,618)
Hardware	(417,518)	-	-	(417,518)
Network	(205,212)	-	-	(205,212)
Meters	(16,992,621)	(26,340,379)	-	(43,333,000)
Total AMI	**(19,482,408)**	**(30,702,940)**	**-**	**(50,185,348)**
Total Capital	**(19,099,636)**	**(30,262,753)**	**1,384,685**	**(47,977,704)**
O&M				
Secure Energy Network	7,000	108,732	-	115,732
Real Time Processing	-	41,840	325,611	367,451
AMI	(669,511)	(1,055,486)	-	(1,724,997)
Distribution technology	-	765,275	-	765,275
Total O&M	**(662,511)**	**(139,639)**	**325,611**	**(476,538)**
Revenue Requirement				
Secure Energy Network	31,298	270,294	-	301,592
Real Time Processing	(0)	131,285	697,943	829,227
AMI	(813,856)	(9,381,054)	-	(10,194,910)
Distribution technology	-	795,887	-	795,887
Total Revenue Requirement	**(782,558)**	**(8,183,588)**	**697,943**	**(8,268,203)**

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Exhibit B

Estimated Benefits from Real Time Processing and Associated Scoping Plan

Summary of potential avoided costs from implementation of the Real Time Processing program

Category of Avoided Cost	$	Reference in Scoping Plan - PGE Exhibit 103 in Docket UE 189
Avoided transformer failure	$77,000	Transformers; on page 9 in avoided transformer failures (low end of range)
Avoided transformer failure	$80,000	Reduced customer outages; on page 9 in avoided transformer failures (low end of range)
Deferred Feeder Conductor Work	$18,000	Year 1; on page 9 in delayed feeder conductor work
Deferred Feeder Conductor Work	$43,000	Year 2 and after; on page 9 in delayed feeder conductor work
Improved Outage Management		
-Avoided Trouble Calls	$23,000	On page 10 in avoided trouble calls
-Improved Storm Management	$37,000	On page 11 in improved storm management
-Expedite Fault Location (a)	$800,000	On page 12 in faster fault identification (low end of estimate); additional cost for sensors required

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.

Demand Response Market Pilot

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

[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.
[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.

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.

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

[6] This example is for a communication-ready water heater; a thermostat trial would have very different results.

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%.

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:

[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.

- 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.

Avoided Service Transformer Failures

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.

Delayed Feeder Conductor Work

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 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.

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

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].

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

[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.

[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).

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 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

PGE Exhibit B

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
Targeted to SF & MF	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
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
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
Cumulative 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
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
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
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
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
System Development	$300,000	$500,000	$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
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
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
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
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
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
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
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

	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
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
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
Customer Attrition	10%		-150	-435	-752	-1,036	-1,203	-1,219	-1,234	-1,248	-1,260	-1,270	-1,280	-1,289
Cumulative 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
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
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
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
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
System Development	$300,000	$500,000	$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
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
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
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
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
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
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
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)

PGE Exhibit B

Demmand Response Market Pilot	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
Not Technology aided	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Targeted to SF & MF														
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
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
Cumulative 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
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
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
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
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
System Development	$300,000	$500,000	$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
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
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
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
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
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
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
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

PGE Exhibit B

	Year 14	Year 15	Year 16	Year 17	Year 18
Demmand Response Market Pilot					
Not Technology aided	2022	2023	2024	2025	2026
Targeted to SF & MF					
NOMINAL SCENARIO					
New Incremental Customers	4,560	4,560	4,560	4,560	4,560
Customer Attrition	-4,323	-4,347	-4,368	-4,387	-4,404
Cumulative Customers	43,465	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	3,477	3,494	3,510	3,523	3,536
total on-peak KW reduction	21,733	21,839	21,935	22,022	22,100
Total $ Benefits	$1,004,911	$1,009,835	$1,014,274	$1,018,274	$1,021,881
Costs					
Program Management	$50,000	$50,000	$50,000	$50,000	$50,000
System Development	$0	$0	$0	$0	$0
Promotion per enrolled customer	$91,200	$91,200	$91,200	$91,200	$91,200
Educational every 5 yrs	$20,000	$100,000	$20,000	$20,000	$20,000
Print/Mail cost each	$84,720	$84,720	$84,720	$84,720	$84,720
one Updates per year	$43,465	$43,678	$43,870	$44,043	$44,199
Critical Pk Notice/event	$130,395	$131,034	$131,610	$132,129	$132,597
Total $ Costs	$419,780	$500,632	$421,400	$422,092	$422,716
Net Benefit (loss)	$585,131	$509,203	$592,874	$596,182	$599,165
Discount Cost of Capital					
NPV	$268,344	$268,344	$268,344	$268,344	$268,344

PGE Exhibit B

Demmand Response Market Pilot						
Not Technology aided		Year 14	Year 15	Year 16	Year 17	Year 18
Targeted to SF & MF		2022	2023	2024	2025	2026
LOW SCENARIO						
New Incremental Customers		1,368	1,368	1,368	1,368	1,368
Customer Attrition		-1,297	-1,304	-1,310	-1,316	-1,321
Cumulative Customers		13,039	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		1,043	1,048	1,053	1,057	1,061
total on-peak KW reduction		4,890	4,914	4,935	4,955	4,973
	Total $ Benefits	$207,581	$208,600	$209,523	$210,351	$211,099
Costs						
Program Management		$50,000	$50,000	$50,000	$50,000	$50,000
System Development		$0	$0	$0	$0	$0
Promotion per enrolled customer		$54,720	$54,720	$54,720	$54,720	$54,720
Educational every 5 yrs		$20,000	$100,000	$20,000	$20,000	$20,000
Print/Mail cost each		$25,416	$25,416	$25,416	$25,416	$25,416
one Updates per year		$13,039	$13,103	$13,161	$13,213	$13,260
Critical Pk Notice/event		$39,117	$39,309	$39,483	$39,639	$39,780
	Total $ Costs	$202,292	$282,548	$202,780	$202,988	$203,176
Net Benefit (loss)		$5,289	-$73,948	$6,743	$7,363	$7,923
	Discount Cost of Capital					
	NPV					
Levelized		($175,897)	($175,897)	($175,897)	($175,897)	($175,897)

PGE Exhibit B

		Year 14	Year 15	Year 16	Year 17	Year 18
Demmand Response Market Pilot						
Not Technology aided						
Targeted to SF & MF		2022	2023	2024	2025	2026
HIGH SCENARIO						
New Incremental Customers		9,120	9,120	9,120	9,120	9,120
Customer Attrition		-8,646	-8,693	-8,736	-8,774	-8,809
Cumulative Customers		86,931	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		6,954	6,989	7,019	7,047	7,072
total on-peak KW reduction		60,852	61,151	61,419	61,662	61,879
	Total $ Benefits	$3,950,145	$3,969,548	$3,986,996	$4,002,719	$4,016,851
Costs						
Program Management		$50,000	$50,000	$50,000	$50,000	$50,000
System Development		$0	$0	$0	$0	$0
Promotion per enrolled customer		$136,800	$136,800	$136,800	$136,800	$136,800
Educational every 5 yrs		$20,000	$100,000	$20,000	$20,000	$20,000
Print/Mail cost each		$169,440	$169,440	$169,440	$169,440	$169,440
one Updates per year		$86,931	$87,358	$87,742	$88,088	$88,399
Critical Pk Notice/event		$260,793	$262,074	$263,226	$264,264	$265,197
	Total $ Costs	$723,964	$805,672	$727,208	$728,592	$729,836
Net Benefit (loss)		$3,226,181	$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	$2,375,624	$2,375,624

PGE Exhibit B

Exhibit C

OPUC Letter of Support

Oregon
Theodore R. Kulongoski, Governor

Public Utility Commission
550 Capitol St NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

July 29, 2009

Donna Williams
U.S. Department of Energy, Office of Headquarters Procurement, MA-64
1000 Independence Ave, SW Washington, DC 20585

RE: Portland General Electric's Applications for the DE-FOA-0000058 Smart Grid Investment Grant Program

Dear Ms. Williams:

We support the Smart Grid Investment Grant applications Portland General Electric (PGE) is submitting to the U.S. Department of Energy. The Oregon Public Utility Commission (OPUC) regulates PGE, and is responsible for assuring that Oregon's investor-owned electric utilities meet customer demands reliably, safely, and at fair and reasonable rates.

The OPUC has allowed PGE to include in rates its investments in smart grid technologies, including investments in more than 800,000 digital smart meters for its residential and small business customers. We support utility efforts to improve the efficiency and reliability of the grid and reduce the need for costly, new generating resources.

We understand that PGE is requesting funds for the following project areas:

- **Secure Energy Network:** PGE will make investments to establish a separate network, isolated from its corporate network, dedicated to the protection of critical cyber assets subject to the NERC Critical Infrastructure Protection standards. The project can be scaled to include PGE's Advanced Metering Infrastructure.
- **Real-Time Processing:** PGE will invest in hardware and software for sensing real-time and interval data feeds from multiple sources and for processing that data in near real-time for analysis. This investment will allow PGE to derive additional benefits from improved outage management, distribution asset utilization, and control infrastructure for demand-side management.
- **Distribution Technology:** PGE will replace its Geographic Information System (GIS), Outage Management System (OMS), and mobile workforce systems with new equipment that maximizes the use of smart devices and allows the field use of GIS and OMS systems.

We expect that PGE may file tariffs to recover some of the costs for these projects. While we cannot commit to ratemaking treatment until after review of the company's filings in a public process, we support PGE's request for funding under the Smart Grid Investment Grant Program.

Sincerely,

Lee Beyer Chairman	John Savage Commissioner	Ray Baum Commissioner

Attachment A

Notice of Application for Deferred Accounting of Incremental Costs and Funds Associated with

Real-time processing & response program,

Secure energy network,

Distribution technology,

and

AMI SGIG funding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM _____

In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects	**Notice of Application for Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects**

On September 4, 2009, Portland General Electric Company ("PGE") filed an application with the Oregon Public Utility Commission (the "Commission") for an Order authorizing deferral of incremental costs and funds associated with the projects for which PGE has filed smart grid investment grant applications.

Approval of PGE's Application will not authorize a change in PGE's rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding.

Persons who wish to obtain a copy of PGE's application should contact the following:

PGE-OPUC Filings
Rates & Regulatory Affairs
Portland General Electric Company
121 SW Salmon Street, 1WTC-0702
Portland, OR 97204
(503) 464-7857 (telephone)
(503) 464-7651 (fax)
pge.opuc.filings@pgn.com

Any person who wishes to submit written comments to the Commission on PGE's application must do so no later than October 5, 2009.

Dated this September 4, 2009.

Patrick G. Hager
Portland General Electric Company
Telephone: 503-464-7580
E-Mail: patrick.hager@pgn.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **Notice of Application for Deferral of Incremental Costs and Funds Associated with Smart Grid Investment Grant Projects** to be served by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. UE 197.

Dated at Portland, Oregon, September 4, 2009.

Patrick G. Hager
Portland General Electric Company

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Summary Report

UE 197 PORTLAND GENERAL ELECTRIC

Category: Electric Rate Case
Filed By: PORTLAND GENERAL ELECTRIC
This filing requests a general rate revision.

Filing Date: 2/27/2008 **Advice No:** 08-02
Effective Date: 1/1/2009 **Expiration Date:** 12/31/2008 **Status:** PERM SUSPEND
See also: UE 198 08-23

Final Order: 09-176 **Signed:** 2/27/2008

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Summary Report

UE 197 PORTLAND GENERAL ELECTRIC

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