Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • Facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

July 27, 2007

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem, OR 97308-2148

Re: UE 189 – Advanced Metering Infrastructure

Attention Filing Center:

Enclosed for filing in UE 189 on behalf of Portland General Electric Company are an original and five copies the testimony of:

- **Bruce Carpenter and Alex Tooman (PGE/100-106) - Cost and Benefits** [Exhibit 104 C is confidential and subject to protective order 07-089. It is provided in separately sealed envelopes and not to be posted on the PUC Website]; and
- **Marc Cody (PGE/200-202) – Pricing.**

Also enclosed are three copies of:

- **Workpapers.** (Confidential and Non-Confidential – Confidential Portion is subject to protective order 07-089. It is provided in separately sealed envelopes and not to be posted on the PUC Website).

Non-Confidential portions are being filed electronically. Hard copies will be sent via postal mail.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:jbf
Enclosures
cc: Service List-UE 189

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 189

Advance Metering Infrastructure
For Prices Effective January 1, 2008

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

July 27, 2007

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Costs and Benefits

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bruce Carpenter – Alex Tooman

July 27, 2007

Table of Contents

I. Introduction

Q. Please state your name and position.

A. My name is Bruce Carpenter. I am General Manager of Revenue Operations.

My name is Alex Tooman. I am a Project Manager in Regulatory Affairs.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe PGE's Advanced Metering Infrastructure (AMI) system as initially proposed in OPUC Docket UE 180 and Advice Filing 07-08. We also respond to issues currently raised by other parties in this docket.

Q. How is your testimony organized?

A. In Section II, we describe the AMI system and reference previous documentation by agreement with other parties to this docket. We also address the costs and benefits of AMI plus the projected revenue requirement impact of AMI for 20 years of the project. In Section III, we describe the updated AMI tariff. In Section IV, we address issues raised by other parties to this docket, specifically the Oregon Public Utility Commission Staff (OPUC Staff or Staff), the Citizens' Utility Board (CUB), and the Community Action Directors of Oregon (CADO). In the last section, we present our qualifications.

Q. Has PGE redrafted its tariff related to AMI?

A. Yes. Because of changes in project timing, some updates to costs and benefits, and the addition of certain provisions for tariff termination (in agreement with OPUC Staff conditions), PGE has redrafted its tariff and included it as PGE Exhibit 202.

Q. What is PGE ultimately seeking with this docket?

A. PGE is seeking a Commission order to file a tariff in compliance with the AMI revenue requirement and timing specified below. In support of this tariff, PGE agrees to numerous conditions and we identify significant cost savings that ultimately provide customers with sizeable net benefits over the life of the AMI project.

Q. Why, specifically, does PGE need this tariff for AMI?

A. The reasons relate to the magnitude and length of the project and its accounting treatment. First, the AMI project represents over $130 million in capital costs and will require over two-and-a-half years to fully implement. Second, unlike most capital projects of that size and length, most of the costs will not be initially charged to construction work in progress (CWIP) and then closed to plant when the project is complete. This would permit AFUDC (allowance for funds used during construction) to be applied to CWIP and a subsequent rate case to reflect the new plant in rate base. With AMI, however, meters comprise over 80% of the project investment and they immediately close to plant when received by PGE. Consequently, without either this tariff or annual rate cases (which we will not pursue, if possible), PGE would receive no recovery on the new system during deployment. In addition, the tariff includes estimated O&M savings during deployment, some components of which could be more difficult to forecast and incorporate in specific test years for rate case purposes.

II. AMI Proposal

A. Project Description

Q. What is PGE's AMI proposal?

A. PGE proposes to install an AMI system that enables the automated collection of meter data via a fixed network. A complete AMI system consists 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, and as a two-way system, sends commands to the meter. This two-way capability enables the utility to send commands to the meter or control devices at the customers' premises.

Q. Has PGE previously provided testimony regarding AMI?

A. Yes. In Docket UE 180, PGE submitted testimony to explain the AMI system and provide initial estimates of costs and benefits. PGE then agreed to remove AMI from that docket and re-submit AMI in a non-general rate case proceeding, which is now UE 189. PGE and other parties also agreed that any previous UE 180 testimony could be incorporated in this docket to avoid repetition on topics that are not in dispute.

Q. Does PGE wish to incorporate testimony previously submitted on AMI?

A. Yes. PGE Exhibit 101 is an excerpt of PGE's UE 180 direct testimony (PGE Exhibit 800), related to AMI. This exhibit provides a summary of the project and explains the benefits that it provides.

Q. Does PGE have any other previously submitted documentation to support this testimony?

A. Yes. PGE submits two additional exhibits in support of its AMI proposal:

- Exhibit 102, PGE's proposed AMI conditions. The proposed conditions represent AMI-related commitments that PGE will pursue pending OPUC approval and successful deployment of the AMI system. This document incorporates most of the additional items requested by Staff and other parties in response to PGE's previous AMI filings, including the draft scoping plan.
- Exhibit 103, PGE's scoping plan. The scoping plan identifies and roughly quantifies additional customer and system benefits not included in PGE's original UE 180 filing. These benefits are derived by programs that the AMI system supports or provides a platform that can be used to develop these programs (e.g., demand response, distribution asset utilization, and outage management).

We explain below how these documents support the various aspects of the AMI proposal.

Q. Has PGE updated its financial analysis of the costs and benefits of AMI since the UE 189 tariff filing on March 7, 2007?

A. Yes. In our work papers we provide electronic spreadsheets with revenue requirement detail of our most recent high-confidence estimate of the costs and benefits related to AMI plus the net present value benefit over the 20-year life of the project. In summary, the primary updates we have made since the UE 189 tariff filing on March 7, 2007, have been in response to the OPUC Staff issues discussed below. PGE has also updated the revenue requirement to reflect the projected change in deployment timing.

B. Project Timing

Q. What is PGE's current time frame for AMI?

A. PGE currently projects that we will begin systems acceptance testing (SAT) by June 1, 2008. We will then begin full deployment in January 2009 and expect to finish in July 2010.

Q. Why did this change in timing occur?

A. It occurred for two reasons – one technical and one regulatory. First, PGE's meter technology vendor (meter vendor) may not be able to complete its scalability testing until this fall. In addition, the meter vendor is not expected to provide host-system software until late 2007. PGE will not sign contracts with the meter vendor and contract meter installer until scalability testing is complete. The delay in providing host-system software means that PGE will probably not initiate SAT until 2008.

Q. What is the regulatory factor contributing to this change?

A. PGE is concerned about the rate impact of implementing AMI given the recent elimination of the BPA residential exchange credit. In order to effectively offset this impact, PGE proposes that we implement the 2008 AMI tariff change at the same time as the expected SB408 credit (June 1, 2008). This will provide additional time for the meter vendor to complete its scalability testing and to develop the host-system software, so that no further delays will be necessary, and it provides Staff and other parties with adequate time to review documentation as described below.

Q. Does the delay in signing the contracts affect the regulatory process for AMI?

A. Yes. The OPUC Staff requested copies of signed contracts with the meter vendor and contract meter installer by July 1, 2007. PGE agrees that this is a reasonable request but we believe that it is in everyone's best interest to wait until scalability testing is complete before signing the contracts.

Q. How does the updated UE 189 schedule address Staff's requirement to review signed contracts?

A. The current schedule is based on the expectation that signed contracts will be available by October 1, 2007. In order to facilitate that review, PGE provided initial copies of draft contracts on July 2, 2007, to Staff and intervenors. When final, signed contracts are available, PGE will provide those copies along with redline/strike-out versions to highlight any changes since the draft contracts were provided. Reply testimony is then scheduled for November 15, to allow adequate time to review the final contracts. The remainder of the schedule was developed so that PGE could receive Commission approval in time to start ordering meters, allowing SAT and the tariff to begin in June 2008.

Q. How would PGE address a delay in signing the contracts?

A. Although PGE believes signed contracts will be available by October 1, 2007, prior experience with this proceeding would indicate that this date is not an absolute certainty. If there is a significant delay in signing the contracts, PGE will discuss the issue with other parties to: 1) address the feasibility of AMI going forward, and 2) establish appropriate timing for subsequent filings and deployment, if AMI remains viable.

C. AMI Costs and Benefits

Q. What are PGE's current estimates of AMI's costs?

A. PGE estimates that the capital costs of AMI will be approximately $132.2 million consisting of the components listed in Table 1.

Table 1
AMI Capital Costs

Component	$Millions
Radio Frequency Meters	70.0
Remote Disconnect Meters (Incremental)	19.3
Meter Installations (loaded)	20.1
System Development (loaded)	9.0
Servers & Storage	6.7
Network Installation (loaded)	5.5
Licenses, Handhelds & Misc.	1.6
Capital Expenditures Total	**132.2**

Q. Why has the estimated capital cost increased since the March 7 filing?

A. The primary reason is that the deployment schedule now includes 2010 and, because of customer growth, there are more *new* meters to install with AMI in 2010 than in 2007. This growth was originally included in the AMI analysis but is now part of the deployment period.

Q. What level of benefits does PGE currently estimate that AMI will provide?

A. PGE has identified two types of benefits that AMI will provide. First, AMI provides operational costs savings as direct benefits of the system. These are described in PGE Exhibit 101 (excerpts from PGE testimony in UE 180) and total approximately $18.2 million[1] in the first full calendar year after full deployment is completed (currently estimated to be 2011). Table 2, below, provides a summary of these benefits.

[1] In addition to $18.2 million in O&M cost savings, PGE estimates that AMI will also produce a $400,000 annual benefit through a working cash reduction in rate base.

Table 2
AMI Operational Savings

Component	$Thousands
Labor Cost	10,967
Non-labor Cost	956
Late Fees	1,737
Energy Unaccounted For	3,632
Power Cost Savings	1,387
Other Savings	(515)
Total Projected Savings - 2011	**18,164**

Q. What is the second type of benefits that AMI provides?

A. The second type is the customer and system benefits that we describe in PGE's Scoping Plan, which is provided as PGE Exhibit 103. As noted above, these benefits are derived by programs that the AMI system supports or provides a platform for developing (e.g., demand response, distribution asset utilization, and outage management). These benefits have the potential to produce significant costs savings in the future but also require additional costs and investment to implement.

Q. When does PGE plan to implement the programs that provide the customer and system benefits?

A. PGE has developed timelines for planning and implementing each program and has listed these in our proposed AMI conditions, which is included in PGE Exhibit 102.

Q. Given the costs and benefits of the AMI system, what is the overall benefit that AMI provides over time?

A. Based on PGE's current estimates of costs and benefits, we calculate that over 20 years, the net present value of the project is:

- Approximately $34 million net benefit based on operational cost savings only.

- A range of approximately $37 million to $80 million net benefit based on the operational costs savings plus customer and system benefits (summary provided as Attachment 1 to PGE Exhibit 103 – PGE's Scoping Plan).

As noted above, the operational costs savings (i.e., direct benefits) are provided by the AMI system as installed, whereas the customer and system benefits will require additional costs and investment. Consequently, the revenue requirement representing AMI, as provided in work papers, includes the direct benefits only.

III. AMI Tariff

Q. What are the regulatory requirements that need to be addressed by your AMI tariff?

A. Deployment of AMI involves three regulatory requirements between when the project starts and when deployment is complete:

- Accelerated depreciation of some existing metering equipment;
- Recovery of new metering equipment as it is deployed; and
- Capture of O&M savings as they begin to occur through the process.

In UE 180, PGE initially proposed inclusion in retail rates of the accelerated depreciation but a deferral mechanism for the other two components. Upon further review, we have determined that a limited term tariff – essentially covering the period of deployment – is a simpler and better approach. The deferral option could raise concerns around ORS 757.355 because the accelerated depreciation of old meters would occur at a much slower rate than in the non-deferral alternative. With a slower rate of accelerated depreciation, cost recovery could occur for an old meter after it had been replaced.

Q. How is the proposed tariff calculated?

A. PGE's proposed tariff reflects approximately $12.9 million for the estimated annual revenue requirement impact of the AMI system, plus accelerated depreciation of the old metering system, less O&M savings during the deployment period. This represents an approximate 0.8% increase on PGE's revenue requirement as determined by OPUC Order No. 07-015 in PGE's last general rate case, Docket UE 180. Specific details for the tariff are addressed in PGE Exhibit 200.

Q. What specific timing does the tariff reflect for each stage of the AMI project?

A. PGE proposes that the AMI tariff become effective June 1, 2008. Initially, it will only include the revenue requirement impact of accelerated depreciation of old meters. The tariff then reflects the following timing:

- SAT begins June 1, 2008.
- SAT completed by mid-December 2008.
- Full AMI deployment begins in January 2009.
- AMI deployment completed in July 2010.

Q. How does PGE avoid conflicts with ORS 757.355 for new meter deployment?

A. To avoid potential conflicts with ORS 757.355, PGE structured the AMI revenue requirement to accomplish two things: 1) recovery of the new system occurs slower than the rate of deployment, and 2) accelerated depreciation of old meters occurs faster than the rate of replacement. The first item is accomplished by incorporating a six-month lag to the schedule listed above, and calculating monthly rate base during the deployment period to reflect the limited deployment during 2008 and lagged deployment in 2009 and 2010.

Q. How does this lag affect the other components of the AMI revenue requirement during the deployment period?

A. Because recovery of new system costs is lagged by six months, PGE has incorporated a similar lag in the recognition of estimated costs savings and we have included an adjustment in 2010 amortization expense to reflect the difference in revenue requirement that would otherwise be achieved without the lag.

Q. How does PGE accomplish the second item related to ORS 757.355?

A. The second item is accomplished by applying most of the accelerated depreciation of the old system at the “front-end” of the tariff. This also allows the revenue requirement to be levelized over the deployment period because cost recovery of the new system primarily occurs at the "back-end" due to the averaging of a lagged rate base.

Q. What are the revenue requirement components of the tariff during the deployment period?

A. The annual revenue requirement impact, by year, by component, is listed in Table 3, below.

Table 3
AMI Annual Revenue Requirement, By Year, By Component

	2008	2009	2010
Old Metering System			
Accelerated depreciation of old meters/system	13,803	12,219	4,986
Return on old meters/system (after tax)	1,729	910	247
Other RevReq of old system (e.g., property andother taxes, etc.)	1,403	821	251
Net revenue requirement on old system	16,935	13,950	5,484
New AMI			
O&M Savings	(173)	(1,332)	(9,158)
Return on AMI (after tax)	786	1,853	7,105
Other RevReq of new system (e.g., return of, property taxes, etc.)	2,328	5,251	16,176
Net revenue requirement on new system	2,941	5,772	14,123
Total revenue requirement impact of AMI	19,876	19,722	19,607
Status Quo Offset			
Return on status quo metering system (after tax)	2,206	2,149	2,103
Return of status quo metering system	3,296	3,239	3,201
Other RevReq of old system (e.g., property and other taxes, etc.)	1,482	1,444	1,410
Net revenue requirement on status quo system	6,984	6,831	6,714
Net revenue requirement impact	12,892	12,891	12,892

IV. Issues Raised by Parties

A. OPUC Staff

Q. What issues did the OPUC Staff raise regarding PGE's AMI proposal?

A. The OPUC Staff raised the following five issues:

1. Staff requested that PGE perform a benefit analysis to remove from plant-in-service the maintenance vehicles used for meter reading purposes, commensurate with the number of meter personnel that will be displaced as a result of the new metering technology. Staff requested that PGE perform the analysis and provide it to Staff by July 1, 2007.
2. Staff proposed that the refund to customers of the Independent Spent Fuel Storage tax credits (ISFSI credits) as filed in Schedule 111 extend beyond 2007, particularly given the delay in the proposed effective date of the tariff. Additionally, Staff proposed that a portion of other deferral balances, such as property sales/gains, also be used as an offset to mitigate any rate impact of the AMI tariff until January 1, 2009.
3. Staff proposed that the State Tax Rate used in the Revenue Requirement Model be adjusted to 5.120% and the Composite Tax Rate in the Revenue Requirement Model be adjusted to 38.328% pursuant to a change in apportionment methods implemented by the Oregon Department of Revenue.
4. Staff proposed that PGE update fuel cost savings in the Financial Model and Revenue Requirement Model to reflect projected fuel costs during the project life or, alternatively, average fuel costs during the past 12 months.

5. Staff proposed that PGE re-compute savings from avoided unaccounted-for-energy based on a value of 0.4%, rather than 0.25%, based on the actual experience of PPL Electric Utilities Corp. (and still below the reported industry range of 0.5% and 2% of sales).

Q. How does PGE respond to Staff's first issue regarding analyzing vehicle retirement?

A. As noted in PGE's response to OPUC Data Request No. 050, PGE had not performed this analysis because we cannot estimate the number of vehicles we will be able to redeploy during or after AMI deployment, or how much PGE will receive for vehicles that it sells. However, if PGE were to make the determination using information available today, we would assume the following:

- There are 125 meter-reading vehicles.
- The current net book value (NBV) of the vehicles is approximately $1.2 million.
- PGE would retain and redeploy approximately 20% of the meter-reading vehicles (i.e., approximately 25 vehicles), and retire and sell the remaining vehicles.
- The estimated selling price per vehicle will range from approximately $1,200 to $11,000, based on PGE's experience selling older vehicles and Kelly's Blue Book for newer vehicles.

Based on these assumptions, PGE would retain and redeploy the 25 newest vehicles with a NBV of approximately $420,000, and we would retire and sell the older 100 vehicles with a NBV of $800,000. We also roughly estimate that proceeds from these sales would be approximately $500,000.

Q. What is the effect of this activity on the AMI project?

A. There is no effect on the AMI project for the following reasons:

- PGE would record the retirements of those vehicles in the depreciation reserve, offset by sales proceeds. This is PGE's standard accounting procedure for asset retirements such as company vehicles.[2]
- This is a very rough estimate based on considerations today. Over the course of AMI deployment, these assumptions will most likely change and the actual transactions related to automobiles could be different.

Q. What is PGE's response to Staff's second issue regarding ISFSI credits?

A. Because the revenue requirement for 2008 is estimated to be $12.9 million, it exceeds the ISFSI credits and other deferral balances available as offsets. As noted above, however, PGE proposes to make the tariff effective on June 1, 2008, when the SB408 credit is available to offset the 2008 rate impact. The June 1 date will also provide additional time for the meter vendor to complete its scalability testing and provide PGE with host-system software.

Q. How does PGE address Staff's third issue regarding the state tax rate?

A. PGE agrees with this adjustment and has incorporated it into our AMI financial model and revenue requirement model. The net effect of this change is to increase the NPV benefit of the project by approximately $700,000.

Q. Does PGE agree with Staff's fourth and fifth issues regarding fuel costs and unaccounted for energy (UFE)?

A. Yes. PGE agrees with both these proposals and has incorporated them into our AMI financial model and revenue requirement model. The net effect of these changes is to increase the NPV benefit of the project by:

[2] PGE customers then receive the benefit of reduced rate base and lower depreciation expense.

- Approximately $400,000 for the change to fuel costs.
- Approximately $3.2 million due to increasing the UFE rate to 0.4%.

Q. Did PGE make any other updates to the financial analysis?

A. Yes. PGE also updated the avoided energy cost related to UFE. In PGE's response to OPUC Data Request No. 041, we noted that this variable had not been updated in October 2006. Staff later indicated that they believed this variable had been updated and, as a result, did not include it in their issues list. PGE had intended to make this update and it results in an increase in the NPV benefit of approximately $12.2 million. In addition, PGE has made a number of smaller corrections that we summarize in Confidential Exhibit 104C.

Q. Did Staff raise any issues other than those in its issues list?

A. Yes. Staff proposed a number of conditions with which PGE agrees and has incorporated into our proposed conditions document. One issue was raised, however, with which PGE does not agree. Specifically, Staff proposed that "PGE will include in the AMI revenue requirement an expected salvage value of $485,000 for the existing meters that will be replaced under the AMI project." Staff has indicated that they selected this amount to create an incentive for PGE to pursue the maximum salvage value.

Q. Does PGE have the ability to significantly influence the amount of meter salvage that is attainable?

A. No, not realistically. Because PGE is not in the business of selling large quantities of used meters, we have to rely on other companies that are in that particular business to identify meter salvage possibilities. In the past, PGE has contracted with Austin International for meter salvage, and we are aware that other companies such as Texas Meter & Device and EMSCO (Electric Motor Supply Co.) offer similar services. For purposes of salvaging over

800,000 meters as a result of the AMI project, PGE will negotiate the best price possible with available buyers, but it is unlikely that we will be able to influence market prices.

Q. What is PGE's response to Staff's condition?

A. PGE does not agree with Staff because we are still exploring the potential for salvaging the meters and are not certain what salvage amount will be realized. In PGE's responses to OPUC Data Request Nos. 463 (UE 180) and 031 (UE 189), we identified a range of possible meter salvage values – from $20,000 to $485,000. In response to OPUC Data Request No. 031, we also stated that, "The sale of used meters, however, is dependent on market demand. With the number of AMI projects forecasted on a national basis, the market may become saturated with old meters and there may be no re-sale value." Ultimately, a meter salvage agreement could entail a fixed price covering PGE's entire AMI deployment or it could be of much shorter duration and require regular (e.g., quarterly) renegotiation or price updates depending on changing market conditions (e.g., PG&E's AMI deployment).

Because $485,000 is at the top of our estimated range and because we do not know if this is attainable, PGE does not believe it is an appropriate amount to include in the AMI financial analysis.

Q. Does PGE have an alternative proposal?

A. Yes. PGE proposes that we continue to add no salvage amount for meters in the AMI financial analysis. Instead, PGE will negotiate the best salvage arrangement possible and incorporate those proceeds in the property sales deferral account for future refund to customers. This way, customers receive the actual meter salvage amount (including an amount greater than $485,000, if it is achieved) and PGE is not harmed if the market for old meters does not produce the currently-estimated, maximum salvage value.

B. CUB

Q. Did CUB raise any issues regarding AMI?

A. Yes. CUB has raised two issues. The first is related to PGE's network meter reading (NMR) investment and argues that these costs should not be included in the accelerated depreciation of PGE's existing metering system.

Q. What does the NMR investment represent?

A. NMR was PGE's advanced metering system as proposed in docket UE 115 and approved by Commission Order No. 01-777. As described in PGE's response to CUB Data Request No. 003, part b (in UE 180), PGE did not fully implement the NMR system envisioned in UE 115. Instead, our primary NMR vendor suffered business failure and we installed a second-choice system to meet the requirements of SB1149. In addition, PGE refunded the difference in revenue requirements between projected and actual information technology investment (including NMR network costs) from 2000 through 2002.

Q. What do these NMR assets represent and what were the costs?

A. PGE Exhibit 105 provides a summary of the NMR components, which customer groups the components served, plus the investment and net book value as of year-end 2006. In total, PGE invested approximately $1.5 million in the NMR network and approximately $6.5 million in NMR meters, which will be replaced by AMI. The net book value of these investments is approximately $4.8 million.

Q. Is PGE replacing its existing metering system in its entirety?

A. No. In total, PGE will replace approximately $30 million (net book value) of existing metering assets. We have, however, identified approximately $5.9 million in meter investment that will be retained if we deploy AMI. These are high-cost meters (for large non-residential customers) that already provide all of the functionality required of AMI meters. The net book value of these assets is approximately $3.7 million as of year-end 2006.

Q. Why does PGE believe it is appropriate to replace the NMR assets with AMI?

A. The NMR system is more costly and less functional than the systems available today. So, if PGE were to install AMI and not replace the referenced NMR components, then O&M costs would increase by approximately $600,000 annually. Although capital costs would also increase to keep the NMR components functional, these are effectively offset by the cost of meters that would not be deployed if the NMR system were to be retained. Further, because the NMR system is not as functional as AMI, if customers with retained NMR components request certain services (such as critical peak pricing), PGE would still need to perform an AMI meter exchange. PGE believes that retaining these systems along with AMI would not be prudent given net benefits associated with AMI.

Q. Has the NMR system served its purposes?

A. Yes. These assets are used and useful to meet the requirements of SB1149. First these assets reduced operating costs on average by approximately $155,000 per year. PGE derives these savings from avoided meter-reading costs on Mt. Hood as well as lower recurring costs to support daily collection of interval data for customers served under direct access. In addition, PGE believes these assets have met an important objective that PGE would gain experience from the investment in order to prepare for full deployment at a later date. In PGE's current technology-evaluation and contracting process, our prior experience has enabled us to negotiate for significant savings.

Q. What does PGE propose in response to CUB's first issue?

A. PGE proposes that the Commission approve its AMI system as prudent and that it authorize accelerated depreciation of its existing metering system including the referenced NMR assets. If the Commission approves the AMI proposal but does not approve the inclusion of the NMR assets in accelerated depreciation of the existing metering system, we request that the Commission allow PGE to update its revenue requirement and tariff for the additional costs needed to keep the NMR system functional.

Q. What was CUB's second issue?

A. CUB's second issue relates to mandatory time-of-use pricing. Specifically, CUB is concerned that PGE's response to OPUC Data Request No. 012, Attachment 012-A, indicates that our long-term strategy is to adopt mandatory time-of-use pricing.

Q. Is this PGE's long-term strategy?

A. No. Attachment 012-A is an AMI business case summary that was presented to PGE's Board of Directors in August 2005. On pages 1-2 and 1-3 of that summary is a description of how AMI can be a major factor in positioning a utility for the future and that a component of that positioning is AMI's ability to "support pricing and demand response options" (page 1-2). While PGE recognizes the importance of demand response programs and their potential benefits, we did not specify mandatory participation as either a goal or an alternative.

Q. Did PGE estimate potential benefits from demand response programs?

A. Yes. In Attachment 012-A, page 1-4, PGE identified a range of possible benefits from a critical peak pricing program as a long-term benefit. This range was approximately $4 million to $34 million.

Q. Did this estimate assume mandatory participation?

A. No. By way of comparison, in PGE's Scoping Plan (Exhibit 103), we estimated a range of potential demand response benefits to be from zero to approximately $27 million. The top end of this range was based on a maximum 10% customer participation rate after five years. In summary, while PGE recognizes the importance of demand response programs for meeting capacity needs in the future, we have only estimated those benefits based on limited <u>voluntary</u> participation. PGE is also aware that any demand response program and associated tariff will be only be implemented after being fully reviewed in a public process and authorized by the Commission as just and reasonable.

C. CADO

Q. What issues has CADO raised regarding AMI?

A. CADO has raised a number of issues which we include in their entirety as PGE Exhibit 106.

Q. How does PGE respond to these issues?

A. PGE acknowledges CADO's concerns and we address a number of them in our proposed AMI conditions document, provided as PGE Exhibit 102. In addition, PGE has scheduled several meetings with CADO and other parties to resolve those issues and develop more detailed commitments, which will then be used to update the AMI Conditions document.

V. Qualifications

Q. Mr. Carpenter, please describe your educational background and experience.

A. I am General Manager of Revenue Operations at Portland General Electric, and am responsible for PGE's metering services, including network metering, meter data acquisition services, and billing and collections functions. I have over 27 years of diverse management and operations experience in the electric utility industry, with special expertise in strategic planning, business processes design, implementation and operations of large, strategic systems. I was president of FirstPoint Utility Services, Inc., a firm providing meter data acquisition, meter services provider, and customer service functionality to energy services providers. I was also president of Si3, a joint-venture metering services company between Portland General Corp. and Itron. I hold a Bachelors Degree in business and an MBA from Oregon State University.

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from The Ohio State University, a Master of Arts degree in Economics from the University of Tennessee, and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs Department since 1996.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Excerpts from PGE's UE 180 testimony directly linked to AMI.
102	Proposed AMI Conditions
103	Scoping Plan of Customer and System Benefits
104C	Summary of PGE Updates to the AMI Financial Model
105	Summary of NMR Components
106	CADO Issues List

II. AMI Proposal

Q. What is AMI?

A. AMI is a system that enables the automated collection of meter data via a fixed network. A complete AMI system consists 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, and as a two-way system, sends commands to the meter. This two-way capability enables the utility to send commands to the meter or control devices at the customers' premises.

Q. Have other Northwest utilities installed systems to automate the meter-reading function?

A. Yes. Puget Sound Energy completed the main deployment of its automated meter reading (AMR) project in 2001. Northwest Natural is installing a drive-by system in parts of its service territory. Clark County Public Utilities completed its system in 2002 and Columbia River PUD will complete its AMI system in 2006. San Diego Gas & Electric and Pacific Gas & Electric are both currently pursuing AMI, and the California PUC recently approved $49 million in "pre-deployment" costs for PG&E's proposed deployment of 9.3 million AMI devices.

Q. How has this recent activity influenced PGE's proposal to implement AMI?

A. This recent activity and the number of parties that have already implemented AMI tell us several things. First, this is a mature technology. PGE would not be a pioneer in the field of AMI; we would be following the lead of a host of other utilities, both large and small, that have seen the value of AMI. Second, we understand from the attention that has been paid to AMI in Oregon that this is a policy issue many parties would like to see addressed. For example, more than fifty parties, including CUB, recently participated in a process to identify opportunities for developing clean energy technologies. That process resulted in a report by Climate Solutions that specifically identified "smart meters" (automated meters) as a recommended part of an overall strategy to "take pressure off overloaded grid infrastructure and power costs, dramatically improve grid reliability and security, and accelerate the growth of cleaner power generation.[1]" In addition, the Energy Policy Act of 2005 states that federal policy is to encourage the deployment of technology to enable demand response programs, including automated metering, and encourages states to do the same. See Energy Policy Act of 2005 Section. No. 1252 (Smart Metering).

Q. Why does PGE propose to implement an AMI system?

A. PGE proposes to implement an AMI system to:

- Reduce operational costs in the long term
- Provide customers with better services such as customer-selected due date, outage detection, and reduced intrusions on their property
- Enable demand response programs
- Provide more accurate and timely billing.

Q. Why does PGE propose to proceed with AMI deployment now?

A. 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. While there are longer-term economic benefits to be gained from implementing AMI, the decision to proceed with this project is also a policy decision. For

[1] Patrick Mazza, Climate Solutions, Powering Up the Smart Grid: A Northwest Initiative for Job Creation, Energy Security and Clean, Affordable Electricity, at 2, 14 (July 2005)

that reason, we are asking the Commission to determine whether it is reasonable for PGE to pursue deployment of an AMI system at this time.

III. AMI System

Q. Please describe the AMI system PGE proposes to deploy.

A. PGE currently proposes to deploy a system with three parts:

1. A combination of radio frequency and power line communication networks that can most effectively and economically gather meter data from our entire service territory.
2. Hardware and software necessary to meet the data collection, storage, and processing requirements plus interfaces with all other necessary PGE systems.
3. Meters with two-way communications that enable accurate recording and transmitting of interval data for all customers.

PGE has issued a Request for Proposals (RFP) for all of the field equipment and all software necessary to manage the equipment that will be used to implement this system. The RFP also makes it clear we are open to other design suggestions that may better meet PGE's needs.

Q. Which classes of PGE's customers would be included in the AMI system?

A. All metered customers, including small non-residential and residential, would be included in the AMI system.

Q. When would the system become operational?

A. PGE has developed an illustrative project timeline that shows complete deployment of approximately 843,000 AMI meters throughout our service territory over the period of 2006-2009. Naturally, because we have just begun the RFP process, a variety of internal and external factors could affect that timeline. It is important to note that PGE already has one key aspect of the AMI system in place, a meter data consolidator (MDC), which we deployed as part of the UE 115 NMR Plan. PGE did not implement the entire NMR Plan contemplated in UE 115 because we found direct access did not proceed as rapidly as anticipated and the technology did not develop as expected. The MDC, however, is currently in use as the system of record for all PGE meter read data, and provides PGE's business systems (e.g., customer billing) with validated data. Because we already have the MDC in place, the AMI system becomes operational shortly after the satisfactory conclusion of the acceptance test on the AMI vendor system, and benefits from AMI start to accumulate as each meter is installed.

Q. What is PGE doing right now with regard to the AMI project?

A. Although PGE does not intend to proceed with full AMI deployment without Commission approval, we have taken a number of steps to evaluate the costs and benefits possible for our customers. We will spend up to $3 million to prepare for project implementation, which includes issuing a RFP, conducting a significant review by the Information Technology organization to estimate the cost of supporting the AMI project, and beginning the public process to support approval for this investment. This preparation also includes the early development work to enable our Customer Information System to automatically accept electronic records that result from meter exchange. Current efforts also include a detailed review and prioritization of all business processes that must be modified to support, or take advantage of, the greater availability of meter data.

IV. Benefits of AMI

Q. What are the primary benefits an AMI system can offer?

A. AMI offers a number of benefits, which we roughly categorize as follows:

- Demand benefits (demand response programs and direct load control)
- Transmission and distribution system benefits (outage reporting, detection, restoration, better distribution planning)
- Economic benefits (cost savings)
- Functional benefits for customers and employees (convenience, safety)

Q. What demand response benefits can an AMI system offer?

A. The system would provide the necessary infrastructure to allow PGE to provide sophisticated demand-side programs. An AMI system permits PGE to offer pricing options and load control options, and provides a mechanism for PGE to "get the most benefit from demand response.[2]" A report issued by the U.S. Department of Energy recently recommended adopting enabling technologies, including automated metering, as a means of encouraging the growth of demand response[3]. It is important to note that some of the demand response benefits will not be recognized immediately and some will require additional investment. For example, the AMI system will allow PGE to offer *smart appliance* services, but not until its customers have smart-appliances. On the other hand, we can offer customer-selected due dates right away. Due date selection ranks highest for PGE

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[2]*See Demand Response Programs for Oregon Utilities, page 35, prepared by Lisa Schwartz for the OPUC, dated May 2003; see also Powering Up the Smart Grid, at 13* (discussing demand response and automated grid technologies, including automated metering).
[3]*See Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, page viii, xx, 58-59, U.S. Dept. of Energy (Feb. 2006)*

customers when asked in surveys about billing and payment programs they would like to see implemented.

Q. How can AMI benefit PGE's transmission and distribution system as a whole?

A. AMI's potential for enhanced outage duration information and reporting, and improved outage detection and restoration potential can help PGE manage outages and improve system reliability. AMI also allows for better distribution planning and improved detection of energy losses.

Q. What economic benefits can result from AMI implementation?

A. PGE anticipates the following economic benefits can result from AMI implementation:

- Elimination of approximately 99% of manual meter reads
- Substantial reduction in the number of service disconnect orders requiring an off-cycle visit
- Remote, on-command meter reads
- Lower costs to open and close accounts in high-turnover dwelling units
- Lower marginal cost to obtain interval data on customer usage
- Reduced cost as a result of identifying sources of energy theft.

Q. Are there other economic benefits that may be realized?

A. PGE may be eligible for significant tax credits related to installation of the AMI system through Oregon's Business Energy Tax Credit (BETC) program. There are other environmental benefits we have not attempted to quantify, such as the many benefits that flow from taking vehicles used for meter reading off the road.

Q. What type of functional benefits can AMI offer PGE's customers?

A. These benefits fall into two primary areas: safety and service. In the area of safety, AMI allows for enhanced outage duration information and reporting and improved outage detection and restoration. It will also reduce the potential for vehicle accidents or physical injury. With regard to service, AMI can lead to fewer property damage and privacy issues, because PGE will not have to visit customer meter locations on a monthly basis, and it allows PGE to offer a customer-selected due date for bills. An AMI system also has the potential to allow customers access to daily usage data so they can respond to price signals and manage their energy usage. However, this latter benefit will require some additions to the AMI system currently proposed by PGE.

Q. Are there long term benefits that will accrue from the AMI project?

A. We believe the most significant long-term economic benefit of AMI is to improve PGE's asset utilization of generation and transmission resources. While the current costs of control technology at the end-use appliance level limits the capture of AMI's technical potential for load control, PGE is actively involved in a number of efforts to reduce costs and increase market acceptance of load control. In the future, we hope to participate in efforts to implement technology that aids in reducing daily peaks with residential appliance control, extended-outage restart assistance, and small-unit (<15KW) distributed generation command, control, and telemetry support. In addition, over the long term, PGE may be able to increase capacity utilization by providing customers with next day time-of-use rates that will allow them to respond to price changes as they do with other products.

Proposed AMI Conditions
July 2007

These AMI Conditions include specific timing that is based upon a tariff effective date of June 1, 2008. Should that date change, the specific times identified in this document may change accordingly.

Operational Implementation Plans

With respect to the detailed implementation plans PGE has provided regarding the operational improvements enabled by AMI, PGE will:

- Quarterly, beginning in April of 2008 and continuing throughout the deployment period, file with the Commission a status report detailing:
  - progress under the implementation plans, including any significant changes in timing, budget, or scope,
  - number of meters installed, and
  - actual costs by category
- If implementation plans are delayed, either due to significant changes made to the overall AMI project scope that affect implementation plans previously provided or to delays associated with the implementation plans themselves, immediately notify the Commission and provide revised implementation plans within 60 days of the notice provided under this condition.
- File draft copies of contracts for AMI equipment and equipment installation by October 1, 2007.
- File copies of contracts for AMI equipment and equipment installation within 15 days of signing including a redline/strike-out version to highlight differences with draft copies.

Customer and System-Related Benefits

PGE believes that development of customer demand response capability and additional tools through which customers can increase their energy efficiency are of great value to our customers' and PGE's future. AMI is foundational to furthering our goals for demand response and greater energy efficiency. Systems-related benefits derived from deployment of AMI will also add value for customers through more efficient use of utility assets and reduction in costs associated with outages. To obtain the greatest benefit from proceeding with AMI, PGE has or will:

- Appointed a Project Manager to lead the effort in developing Project Charters and Project Plans (implementation plans) in each of the following benefit areas:

  - Information-driven Energy Savings

- Distribution Asset Utilization
- Outage Management

Demand Response initiatives are already being addressed by organizations within PGE and do not need additional project management.

- Provided to OPUC Staff and CUB the Project Charters on June 29, 2007. A meeting was conducted on July 9, 2007 to obtain input and feedback on the charters.

- By May 1, 2008, provide OPUC Staff and CUB the detailed implementation plans (Project Plans). The project plans will include the same level of detail as the implementation plans provided for the operational benefits, with specifics as detailed below.

- After the deployment period and continuing through the conclusion of the first general rate case following deployment, file quarterly status reports on customer and systems-related benefits with the Commission (within 30 days of each calendar quarter) showing savings, costs and operational progress to the previously filed implementation plans.

- Three months following the first and third year after each demand response program is first offered, file with the Commission a report evaluating each program in the preceding year, including itemized program costs, estimated capacity and costs savings, consumer survey results, and the Company's recommendations on whether to continue, modify or terminate the program(s).

- For CPP programs, six months following the first and second year after the pricing option is first offered, file an evaluation report with the Commission including program costs, estimated capacity savings, customer acceptance results, and recommendations for modifications.

Demand Response

PGE's initial efforts to develop incremental demand response will occur through:

- IRP Capacity Planning
- Voluntary Critical Peak Pricing
- Appliance Market Transformation

IRP Capacity Planning

PGE is presently engaged in an Integrated Resource Planning (IRP) process that assesses the availability and cost-effectiveness of firm demand side resources to meet system capacity needs. In the draft IRP that PGE issued in the second quarter of 2007, PGE included in its proposed capacity actions all estimated achievable potential for firm direct load control[1], as a placeholder, under the assumption that this will be the achievable, cost-effective potential that can be reached upon implementation of AMI. PGE has also included 30 MW for curtailment and critical peak pricing (CPP) tariffs, as a placeholder, under the same assumptions of being achievable and cost effective.

To follow-up on the curtailment tariff, PGE will:

- Within twelve months of filing its 2007 IRP, file a tariff implementing a dispatchable capacity peak reduction program to help meet system capacity needs. The cost effectiveness of such a program will be determined as part of the investigation of the tariff.

Voluntary Critical Peak Pricing

AMI meters will support a time varying pricing options. PGE is planning to implement an experimental tariff for critical peak pricing once the AMI infrastructure is in place. For a CPP program, PGE will or has:

- Provided to OPUC Staff and CUB, on May 1, 2007, a summary document on Critical Peak Pricing. The document addresses market monitoring of other utility efforts, including the California Statewide Pricing Pilot, as well as enabling technologies that may support critical peak pricing.
- Engaged OPUC Staff, CUB and other interested stakeholders in review of program options at a July 9, 2007 meeting and through other discussions and electronic communications.
- By July 1, 2008, prepare an experimental tariff reflecting stakeholder input for Commission consideration.

Appliance Market Transformation

PGE clearly understands that as a mid-sized utility in Oregon, we do not have the political power or resources to drive significant market transformation. However, we do believe we can assist in moving towards that transformation by working with an appliance manufacturer with whom we already have developed a relationship to modify an agreed upon appliance to (1) receive price and/or control signals from the utility, and (2) include a simple control 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. To move this effort forward, PGE will or has:

[1] Per *Update of Demand Response Resource Potentials for PGE,* Quantec, February 6, 2007.

- Engaged regional stakeholders and appliance manufacturers to identify interest in a technology trial for either water heaters or thermostats.
- Assembled a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties to develop a project to create a 5 - 10 MW demand response resource through an appliance market-transformation approach that, if awarded, will activate a USDOE grant by March of 2008. If the grant is not awarded to the consortium, provide a written report to OPUC Staff and CUB detailing barriers to proceeding by May 1, 2008.

Information-Driven Energy Savings

PGE believes that energy usage information derived from AMI interval data will reveal energy savings strategies that customers will value. To test this hypothesis, PGE has performed market research to determine energy usage information. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to share the results of research to date, the plans for additional research to determine customer interest in energy usage information, and the plans to implement a program to meet customer interest.

Distribution Asset Utilization

The underlying assumption in the area of distribution asset utilization 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. AMI can affect:

- Avoided Service Transformer Failures
- Proper Transformer Sizing
- Delayed Feeder Conductor Work, Including Load Balancing of Substation Transformers

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. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to service transformers.

Proper Transformer Sizing

The new regression model described above could also be used to address oversized transformers currently used. PGE has a program today to analyze transformer loading and replace oversized transformers when the replacement is determined to be cost effective. This program uses monthly kWh usage data assembled in the company's TIVO database to estimate the peak loading of these transformers. Use of interval data to more accurately identify peak loading conditions could better determine oversized transformers leading to more effective use of these resources. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to proper transformer sizing.

Delayed Feeder Conductor Work

PGE currently plans feeder reconductor work each year to resolve overloading conditions on sections of affected feeders. With better loading information from AMI interval data on sections and taplines associated with these feeders, some of this work could be deferred or delayed. The better data may allow loads to be shifted to other feeders which could result in a delay in the need to complete the reconductor work. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to apply the loading information to feeder conductor work.

Outage Management

After the deployment of an AMI system (2010), PGE is planning to upgrade its current Outage Management System (OMS). To ensure proper consideration of outage management improvements enabled by AMI both before and after OMS replacement, PGE will:

- By 2010, develop AMI interface specifications needed to support integration with the new OMS.

Prior to the OMS upgrade, actions that can be taken to improve outage management using the new AMI system will be considered. These actions for consideration are addressed below.

Avoided Trouble Calls

PGE estimates that for a fraction of trouble calls 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). PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this query function to avoid trouble calls.

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. 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. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this process to improve one-premise outage response.

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’s service without having to return later saves outage time and utility costs. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this detection function to improve storm management.

Faster Fault Location Identification

Approximately half of PGE's SAIDI (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 PGE's selected 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. Using these devices in conjunction with the AMI system would reduce the time to find these faults significantly and improve SAIDI statistics. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of these fault detection devices.

Regulatory Filings

PGE commits that if it 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. In addition, after 2010, if PGE is not currently engaged in a general rate proceeding, the Commission may request no later than July 1, 2012, that PGE submit a general rate filing in Oregon no later than eight months thereafter. PGE shall bear the burden of proof in such filing, in accordance with ORS 757.210

Coordination with Northwest Natural Gas Company (NWN) in Joint Meter Reading Area

PGE Revenue Operations management has been talking with NWN management on a periodic basis to inform them of our plans and progress towards deployment of an AMI system and to ascertain their plans for automation within the joint meter reading area. PGE has shared with NWN the specific AMI technology vendor selected and NWN has had several meetings with that vendor to determine whether or not they might consider use of that vendor in the joint meter reading area. To assure coordination that has the least possible financial impact upon customers continues, PGE will:

- Quarterly, beginning in April of 2008 and throughout the deployment period, report to the OPUC Staff and CUB on ongoing coordination discussions between PGE and NWN and actions being taken to assure continued coordination with the least possible financial impact upon customers during deployment.

Community Action Directors of Oregon (CADO) and Oregon Energy Coordinators Associations (OECA) Conditions

Discussions between CADO and PGE have identified several areas of potential impact upon PGE's low-income customers as a result of the implementation of AMI. Each of these areas is addressed below.

Remote Disconnect/Reconnect

Administrative Rules have been established to address the use of Remote Disconnect/Reconnect functionality. These rules outline the specific communication requirements that PGE must meet in disconnecting and reconnecting a customer. CADO and OECA are concerned that PGE's low-income customers understand the rules ahead of time so that they can properly seek the assistance they need in paying their utility bill. To assist in educating customers, PGE will, by October 1, 2007, meet with Community Action Agencies (CAAs) and other parties to:

- Begin development of effective communications on remote disconnect/reconnect rules. These communications may include brochures, DVDs for use in agency and community offices and materials used in Energy Education Workshops.

- Explore possible customer assistance program offerings to help low-income customers stay current with their PGE bill and remain connected to the PGE electrical system.

Leveraging Data

AMI provides for the collection and assembly of real-time customer data that will enable PGE to deliver benefits described above in this conditions document. To assist CAAs and low-income customers in accessing electricity usage information to manage their electric bills, PGE will, by October 1, 2007, meet with CAAs and other parties to:

- Discuss how electricity usage information can be made available to low-income customers and possibly the CAAs so that the agencies can properly assist these customers.

Long-Term Benefits of AMI Functionality

As part of demand response and appliance market transformation programs discussed earlier in this document, there is the potential for new technologies to be made available in the market place in the form of "smart" appliances and in home communications devices providing pricing information. To assure that low-income customers are provided access to this new technology, PGE will:

- Prior to making these new technologies available to the general customer base, meet with CAAs and other parties to determine special programs that could be enacted to provide low-income customers with access to the new technologies.

Pre-Paid Electric Metering

Pre-paid metering is not a program or functionality that will be included as part of the AMI deployment project. PGE has, however, discussed using the AMI technology to pilot a pre-paid metering program. To assure that low-income customers are not disadvantaged by this potential program, PGE will:

- Prior to implementing a pre-paid metering pilot program, meet with CAAs and other parties to establish acceptable parameters around the usage of pre-paid metering for low-income customers.

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:

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[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.

<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 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].

<u>Faster Fault Location Identification</u>

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.

<u>Reduced Contact Center Cost</u>

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

Attachment 2

Analysis of Demand Response Benefits

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
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
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

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
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
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
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)

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
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

	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
Cumlulative 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

	Year 14	Year 15	Year 16	Year 17	Year 18
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
Cumlulative 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)

		Year 14	Year 15	Year 16	Year 17	Year 18
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
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
Cumlulative 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

NMR Costs to Replace
Net Book Value at year end 2006

Job	Description	NMR Purpose	Network Investment	Meter Investment	Total Investment	Network NBV	Meter NBV	Total NBV
Job 19731	Whisper	Mostly residential		905,935	905,935		476,546	476,546
Job 19731	Hunt-PLC	100% residential		827,808	827,808		505,905	505,905
Job 19734	Meter Reading Network	Mostly residential	584,950		584,950	306,613		306,613
Job 20293	SmartSynch	Commercial		4,763,859	4,763,859		2,868,137	2,868,137
Job 21706	TS1-PLC Network	100% residential	384,059		384,059	257,947		257,947
Job 21708	TS2-PLC Network	Mostly residential	169,767		169,767	117,336		117,336
Job 21887	TS2-PLC Network	Mostly residential	340,122		340,122	273,856		273,856
	Totals		1,478,898	6,497,602	7,976,500	955,753	3,850,588	4,806,341
	Total Residential				3,212,641			1,938,204
	Total Commercial				4,763,859			2,868,137
	Totals				7,976,500			4,806,341

PLC = Power Line Carrier

Docket UE 189
CADO / OECA Issues List
June 1, 2007

The Community Action Directors of Oregon (CADO) and the Oregon Energy Coordinators Association (OECA) present this proposed list of issues. These issues identify many of the potential impacts we believe AMI will have on PGE's low-income customers. These issues were discussed at the Advanced Metering Infrastructure (AMI) workshop on April 24, 2007. CADO and OECA reserve the right to add additional relevant issues, or to modify these issues, as warranted by the development of this case.

Implementation of new administrative rules. The initial phase of AMI will enable the implementation of remote customer disconnect / reconnect functionality.

- How can PGE, working in concert with the appropriate Community Action Agencies (CAAs) and other parties, most effectively prepare, educate, and assist low-income customers for the implementation of the new OPUC Administrative Rules that come into effect with the installation of remote disconnect / reconnect technology?

- Working in concert with CAAs and other appropriate parties, what new and/or enhanced customer assistance program offerings can PGE develop, adapt, and assist to deliver that will help low-income customers stay current with their PGE bills, remain connected to the PGE electrical system, and be able to take advantage of the advanced benefits and program offerings that AMI promises to deliver to customers in the future?

Leverage Data. AMI provides for the collection and assembly of real-time customer data that will enable PGE, among other things, to deliver benefits under the general headings of Demand Response Programs and Information-Driven Energy Savings.

- How can the detailed, "micro-customer" data generated through AMI best be utilized by PGE and the CAAs in identifying and assisting low-income customers who are struggling to stay current with their electricity bills?

- How can the real time information available through AMI be shared, and best utilized, between PGE and the CAAs to assist low-income customers in the provision of programs such as; bill payment assistance, energy education, case management, arrearage management, weatherization, appliance replacement, and other existing low-income programs and those yet to be developed?

Long-Term Benefit of AMI Functionality. Among the benefits of AMI is the coupling of the enhanced information systems with ‘smart’ appliances and devices that can accept and respond to price signals and other communications provided by PGE.

- How can PGE assist in making smart appliances and electricity-consuming devices available to low-income customers?

- How can PGE assist CAAs and others ensure that expected market transformations in appliance stocks and energy monitoring and control technologies do not bypass low-income customers?

- How can PGE best assure that low-income customers have the capability to participate in demand shifting / management, peak pricing, and other valuable programs enabled the AMI?

Pre-Paid Electric Meters. Pre-paid electric meters are a functionality offered by AMI. This functionality can be detrimental to low-income customers in a number of ways.

- How will PGE ensure that low-income customers who have difficulty remaining current with their electricity bills remain connected to the system?

- How will PGE ensure that this functionality of AMI is not used as an ‘arrearage management’ tool?

- What protections can PGE develop and put into place to help ensure that low-income customers are not disadvantaged and/or endangered by this AMI functionality?

UE 189 / PGE / 200
CODY

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

July 27, 2007

Pricing

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section IV.

Q. What is the purpose of your testimony?

A. This testimony demonstrates how the prices contained in proposed Tariff Schedule 111 Advanced Metering Infrastructure are calculated and provides an estimate of the 2008 rate impacts from proposed Schedule 111 for selected rate schedules.

II. Estimated Prices and Rate Impacts

Q. Please list the projected Schedule 111 prices and accompanying rate impacts for 2008 resulting from this filing.

A. Table 1 below summarizes the preliminary price estimates and the rate impacts for 2008 for selected Schedules. I anticipate updating these prices consistent with the final order in this docket and an updated load forecast. The discussion of how these prices are calculated is contained in the following section of this testimony.

Q. Do you have any exhibits that support how you developed these prices?

A. Yes, Exhibit 201 contains the revenue requirement allocation and price development detail and Exhibit 202 contains the proposed tariff Schedule 111.

Table 1
Estimated Prices and Rate Impacts

Schedule	Price (mills/kWh)	Rate Impact
Sch 7 Residential	1.21	1.2%
Sch 32 Small Non-residential	1.38	1.4%
Sch 83 Secondary	0.16	0.2%
Sch 83 Primary	0.25	0.3%
Sch 89 Secondary	0.01	0.0%
Sch 89 Primary	0.02	0.0%
Sch 89 Subtransmission	0.05	0.1%
Overall		0.8%

III. Cost Allocation and Pricing

Q. Please describe how you allocated the AMI revenue requirement to each Schedule.

A. I first categorized the total revenue requirement of $33.3 million into three components: 1) the revenue requirement associated with the existing metering system; 2) the revenue requirement associated with the O&M savings attributable to the new AMI system and; 3) the revenue requirement associated with the new AMI system net of the O&M savings. The first component consists of accelerated depreciation of the old meters, return requirements of the old metering system, and other items such as property taxes. The second component is primarily reduced meter reading expense, and the third component consists of the return on and of the new AMI system as well as items such as property taxes. I then calculated the percent to which each of these three categories contributes to the total revenue requirement and applied these percent contributions to the annualized revenue requirement of $12.9 million. As demonstrated on Exhibit 201 page 1, approximately $4.5 million (35.1%) of the annualized revenue requirement relates to the existing system, -$4.1 million (-31.8%) relates to the O&M savings of new AMI system, and $12.5 million (96.7%) relates to the deployment of the new AMI meters.

I allocated the annualized $4.5 million related to the existing system based on the final UE 180 allocated distribution revenue requirement associated with the installed costs of meters. I allocated the $4.1 million of annualized O&M savings based on the final unbundled UE 180 Metering revenue requirement allocation. Finally, I allocated the annualized $12.5 million associated with the AMI meters based on annualized AMI installed meter costs. Page 2 of Exhibit 201 contains a summary of the total allocations including a rate mitigation adjustment that limits the base rate increase to no more than 3% for any

Schedule. Page 3 of Exhibit 201 contains the Schedule 111 price calculations based on the allocations discussed above and a projection of 2009 energy consumption. Finally, Exhibit 201 page 3 also demonstrates the 2008 price impacts of Schedule 111 for each Cost of Service Schedule.

Q. Please explain how this allocation of revenue requirement differs from that contained in PGE Advice Filing 07-08.

A. In Advice Filing 07-08 the proposed allocation was based on invested capital in order to approximate the long-term costs and benefits of AMI. These long-term costs and benefits will be incorporated into future rate proceedings where the benefits are more easily specified and assigned to functional revenue requirements. I believe that the allocation proposed above, one based on a more narrowly defined period is preferable because it concentrates on the specific costs and benefits during the period which Schedule 111 will be in effect.

Q. Please describe the changes you have made to the proposed tariff, Schedule 111 since you initially filed in March.

A. I have made the following changes to Schedule 111 as originally filed (Exhibit 202):

1. Eliminate the Part B ISFSI offset because the ISFSI credits are likely to be used to offset the Boardman deferral amortization.
2. Incorporate language that establishes the effective date as June 1, 2008, instead of July 1, 2007, and extends the term to December 31, 2010, instead of December 31, 2009.
3. Incorporate language that provides for termination of Schedule 111 should Systems Acceptance Testing (SAT) prove unsuccessful. Also included as Special

Condition 2, is a provision that allows for temporary suspension of Schedule 111 in order to resolve potential issues related to SAT.

Q. Have you made other substantive changes to the proposed tariff?

A. No.

IV. Qualifications of Witness

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	Revenue Requirement Allocation and Price Development Detail
202	Proposed Schedule 111

AMI Allocations ($000)

Revenue Requirement of Existing System	$11,693	35.1%
Revenue Requirement of AMI Meters	$32,201	96.7%
O&M Savings	($10,591)	-31.8%
Total	$33,303	100.0%

Annualized Revenue Requirement	$12,892
Existing System	$4,526
New System Meters	$12,465
O&M Savings	($4,100)

Allocations based on UE-180 Meter Costs ($000)

Schedule	UE-180 Meter Revenue Requirement	Allocation Percent	Existing System Allocation
Schedule 7	$8,463	62.8%	$2,842
Schedule 32	$2,545	18.9%	$855
Schedule 38	$150	1.1%	$50
Schedule 47	$160	1.2%	$54
Schedule 49	$148	1.1%	$50
Schedule 83-S	$1,433	10.6%	$481
Schedule 83-P	$192	1.4%	$64
Schedule 89-S	$18	0.1%	$6
Schedule 89-P	$147	1.1%	$50
Schedule 89-T	$187	1.4%	$63
Schedule 93	$35	0.3%	$12
Totals	$13,479	100.0%	$4,526
		TARGET	$4,526

Allocations Based on AMI Meter Costs ($000)

Schedule	2009 Average Customers	Marginal Unit Cost per Customer	Marginal Cost Revenues	Allocation Percent	Allocated Revenue Requirement
Schedule 7	719,730	$13.91	$10,011	80.7%	$10,060
Schedule 32	84,116	$20.07	$1,688	13.6%	$1,696
Schedule 38	1,092	$39.44	$43	0.3%	$43
Schedule 47	3,167	$28.93	$92	0.7%	$92
Schedule 49	1,333	$42.61	$57	0.5%	$57
Schedule 83-S	12,175	$40.67	$495	4.0%	$498
Schedule 83-P	147	$45.58	$7	0.1%	$7
Schedule 89-S	109	$45.58	$5	0.0%	$5
Schedule 89-P	118	$45.58	$5	0.0%	$5
Schedule 89-T	10	$45.58	$0	0.0%	$0
Schedule 93	27	$40.08	$1	0.0%	$1
Totals	822,023		$12,405		$12,465
			TARGET		$12,465

Allocations based on UE-180 Metering Revenue Requirement ($000)

Schedule	UE-180 Metering Revenue Requirement	Allocation Percent	Existing System Allocation
Schedule 7	$15,134	87.6%	($3,590)
Schedule 32	$1,763	10.2%	($418)
Schedule 38	$27	0.2%	($6)
Schedule 47	$68	0.4%	($16)
Schedule 49	$28	0.2%	($7)
Schedule 83-S	$255	1.5%	($60)
Schedule 83-P	$3	0.0%	($1)
Schedule 89-S	$2	0.0%	($1)
Schedule 89-P	$2	0.0%	($1)
Schedule 89-T	$0	0.0%	($0)
Schedule 93	$1	0.0%	($0)
Totals	$17,284	100.0%	($4,100)
		TARGET	($4,100)

Total Allocations ($000)

Schedule	Estimated 2008 Base Revenues	Existing System Allocation	New System Allocation	3% Increase Mitigation	Mitigation Allocation	Total Allocation
Schedule 7	$767,581	$2,842	$6,470	$0	$53	$9,365
Schedule 32	$144,945	$855	$1,278	$0	$12	$2,145
Schedule 38	$10,004	$50	$37	$0	$0	$88
Schedule 47	$2,238	$54	$76	($62)	$0	$67
Schedule 49	$4,870	$50	$50	$0	$1	$101
Schedule 83-S	$428,436	$481	$437	$0	$5	$924
Schedule 83-P	$20,143	$64	$6	$0	$0	$71
Schedule 89-S	$53,114	$6	$4	$0	$0	$10
Schedule 89-P	$187,991	$50	$5	$0	$0	$55
Schedule 89-T	$77,853	$63	$0	$0	$0	$64
Schedule 93	$87	$12	$1	($10)	$0	$3
Totals	$1,697,261	$4,526	$8,365	($72)	$72	$12,891

Note: DA customers priced at COS

Schedule 111 Prices

Schedule	2009 MWH	Allocation	Sch 111 Price mills/kWh	Revenues
Schedule 7	7,718,635	$9,365	1.21	$9,340
Schedule 32	1,553,737	$2,145	1.38	$2,144
Schedule 38	104,615	$88	0.84	$88
Schedule 47	22,035	$67	3.05	$67
Schedule 49	66,952	$101	1.50	$100
Schedule 83-S	5,641,894	$924	0.16	$903
Schedule 83-P	283,954	$71	0.25	$71
Schedule 89-S	739,697	$10	0.01	$7
Schedule 89-P	3,124,248	$55	0.02	$62
Schedule 89-T	1,286,538	$64	0.05	$64
Schedule 93	562	$3	4.65	$3
Totals	20,542,866	$12,891		$12,850

Note: Total MWH does not include unmetered schedules 15, 91, 92, 94
Note: 2009 energy used to develop prices

Summary of AMI Changes for COS Customers

Schedule	2008 Cycle Energy (MWH)	Sch 111 Price mills/kWh	Change in Revenues	Estimated Prior Revenues	Percent Change
Schedule 7	7,643,451	1.21	$9,248,576	$784,396,733	1.2%
Schedule 15	23,746	0.00	$0	$4,102,447	0.0%
Schedule 32	1,516,483	1.38	$2,092,746	$148,386,920	1.4%
Schedule 38	103,460	0.84	$86,906	$10,240,668	0.8%
Schedule 47	21,742	3.05	$66,314	$2,289,296	2.9%
Schedule 49	66,065	1.50	$99,098	$4,997,848	2.0%
Schedule 83-S	5,499,638	0.16	$879,942	$439,011,806	0.2%
Schedule 83-P	278,446	0.25	$69,612	$20,694,183	0.3%
Schedule 89-S	691,188	0.01	$6,912	$51,620,565	0.0%
Schedule 89-P	1,926,198	0.02	$38,524	$130,230,327	0.0%
Schedule 89-T	778,139	0.05	$38,907	$48,790,800	0.1%
Schedule 91	103,260	0.00	$0	$17,458,128	0.0%
Schedule 92	5,612	0.00	$0	$425,983	0.0%
Schedule 93	562	4.65	$2,615	$88,742	2.9%
Schedule 94	241	0.00	$0	$18,268	0.0%
76-R	25,114	0.05	$1,256		
Schedule 483-S	4,978	0.16	$796		
Schedule 483-P	0	0.25	$0		
Schedule 489-S	30,567	0.01	$306		
Schedule 489-P	932,895	0.02	$18,658		
Schedule 489-T	477,161	0.05	$23,858		
Totals	20,128,946		$12,675,025		
COS Totals	18,658,231		$12,630,151	$1,662,752,713	0.76%

Note: Prior revenues include supplemental schedules

SCHEDULE 111
ADVANCED METERING INFRASTRUCTURE

PURPOSE

To recover from Customers the revenue requirement impact of newly installed Advanced Metering Infrastructure (AMI), less Operations and Maintenance (O & M) cost savings, plus the accelerated depreciation for meters that AMI will replace.

APPLICABLE

To all bills for electric service calculated under all rate schedules listed below.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after June 1, 2008, will be:

Schedule	Adjustment Rate	
7	0.121	¢ per kWh
32	0.138	¢ per kWh
38	0.084	¢ per kWh
47	0.305	¢ per kWh
49	0.150	¢ per kWh
75		
Secondary	0.001	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.005	¢ per kWh
76R		
Secondary	0.001	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.005	¢ per kWh
83		
Secondary	0.016	¢ per kWh
Primary	0.025	¢ per kWh
87		
Secondary	0.001	¢ per kWh
Primary	0.002	¢ per kWh
Subtransmission	0.005	¢ per kWh

PROPOSED TARIFF DO NOT BILL

SCHEDULE 111 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Adjustment Rate
89	
Secondary	0.001 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.005 ¢ per kWh
93	0.465 ¢ per kWh
483	
Secondary	0.016 ¢ per kWh
Primary	0.025 ¢ per kWh
489	
Secondary	0.001 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.005 ¢ per kWh
532	0.138 ¢ per kWh
538	0.084 ¢ per kWh
549	0.150 ¢ per kWh
575	
Secondary	0.001 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.005 ¢ per kWh
576R	
Secondary	0.001 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.005 ¢ per kWh
583	
Secondary	0.016 ¢ per kWh
Primary	0.025 ¢ per kWh
589	
Secondary	0.001 ¢ per kWh
Primary	0.002 ¢ per kWh
Subtransmission	0.005 ¢ per kWh

SCHEDULE 111 (Concluded)

SPECIAL CONDITIONS

1. This Schedule will terminate within six months or less of the effective date if Systems Acceptance Testing is not successful or alternatively if the Company does not commence mass deployment of meters within 75 days of completion of Systems Acceptance Testing.

2. This Schedule may be temporarily suspended in order to resolve specific issues identified during Systems Acceptance Testing. The Company must file an application to suspend at least 45 days before the termination deadline specified in Special Condition 1.

TERM

This adjustment schedule will terminate December 31, 2010.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **TESTIMONY OF PORTLAND GENERAL ELECTRIC COMPANY (PGE/100-106/Carpenter-Tooman/Cost and Benefits) and (PGE/200-202/Cody/Pricing)** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and 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 189.

Dated at Portland, Oregon, this 27th day of July 2007.

DOUGLAS C. TINGEY

SERVICE LIST

OPUC DOCKET # UE 189

CITIZENS' UTILITY BOARD OF
OREGON
LOWREY R BROWN,
lowrey@oregoncub.org
(Paper service waived)

CITIZENS' UTILITY BOARD OF
OREGON
JASON EISDORFER,
ENERGY PROGRAM DIRECTOR
jason@oregoncub.org
(Paper service waived)

CITIZENS' UTILITY BOARD OF
OREGON
ROBERT JENKS
bob@oregoncub.org
(Paper service waived)

DEPARTMENT OF JUSTICE
STEPHANIE S ANDRUS, AAG
REGULATED UTILITY & BUSINESS
SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us

DEPARTMENT OF JUSTICE
JANET L PREWITT, ASST AG
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

OREGON DEPARTMENT OF ENERGY
ROBIN STRAUGHAN
robin.straughan@state.or.us
(Paper service waived)

PACIFIC POWER & LIGHT
MARK TUCKER, REGULATORY
ANALYST
mark.tucker@pacificorp.com
(paper service waived)

DAVISON VAN CLEVE PC
MATTHEW W PERKINS
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mwp@dvclaw.com

S BRADLEY VAN CLEVE
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mail@dvclaw.com

NORTHWEST NATURAL
INARA K SCOTT
REGULATORY AFFAIRS MANAGER
inara.scott@nwnatural.com
(paper service waived)

NW NATURAL
RATES & REGULATORY AFFAIRS 220
efiling@nwnatural.com
(paper service waived)

COMMUNITY ACTION DIRECTORS OF
OREGON
JIM ABRAHAMSON, COORDINATOR
PO BOX 7964
SALEM OR 97301
jim@cado-oregon.org

PACIFICORP
OREGON DOCKETS
oregondockets@pacificorp.com
(waived paper service)

OREGON PUBLIC UTILITY
COMMISSION
LISA C SCHWARTZ,
PO BOX 2148
SALEM OR 97308-2148
lisa.c.schwartz@state.or.us