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Cece L. Coleman
Assistant General Counsel

November 21, 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 – In the Matter of Portland General Electric Request to Add Schedule 111, Advanced Metering Infrastructure (AMI)

Attention Filing Center:

Enclosed for filing in UE 189 are an original and five copies of:

- **Joint Direct Testimony of Lisa Schwartz, Carla Owings and Alex Tooman; and**
- **Exhibits (JOINT/100-105).**

Also enclosed are an original and one copy of:

- **Stipulation (including Conditions).**

Finally, enclosed are three copies of:

- **Workpapers.** (Confidential and Non-Confidential subject to Protective Order 07-089 and therefore not to be posted on the PUC website. They are in Excel file format and will be sent electronically via CD).

These documents are being filed electronically. Hard copies will be sent via postal mail.

Finally, in recognition of the ALJ's request that the parties propose a schedule for the remainder of the docket, below is Portland General Electric Company's proposed schedule:

Response testimony - CUB and others: (Begin 5 day discovery turnaround)	December 10
Reply Testimony:	December 21
Opening briefs:	January 11
Closing briefs:	January 25

This schedule has been shared with the parties, and CUB has specifically asked for further time to comment. In light of the circumstances, PGE would propose that all parties be afforded the opportunity to comment upon this schedule on or before the close of business Thursday, November 29, 2007, and in the meantime we will work with the parties in an effort to finalize it sooner, if possible.

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,

Cece L. Coleman

CECE L. COLEMAN

CLC: saa
Enclosures
cc: Service List-UE 189

UE 189 / JOINT / 100
SCHWARTZ – OWINGS – TOOMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Testimony in Support of the AMI Stipulation

PORTLAND GENERAL ELECTRIC COMPANY
&
OREGON PUBLIC UTILITY COMMISSION

Joint Direct Testimony and Exhibits of

Lisa Schwartz – Carla Owings – Alex Tooman

November 21, 2007

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Lisa Schwartz. I am a Senior Analyst in the Electric and Natural Gas Division of the Oregon Public Utility Commission (OPUC) Staff. My qualifications appear at the end of this testimony.

My name is Carla Owings. I am a Senior Revenue Requirement Analyst in the Rates and Tariffs section of the Electric and Natural Gas Division of the OPUC Staff. My qualifications appear at the end of this testimony.

My name is Alex Tooman. I am a Project Manager in Regulatory Affairs for PGE. My qualifications appear in Section V of PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. Our purpose is to describe the Stipulation reached among the OPUC Staff, the Oregon Department of Energy (ODOE), the Community Action Partnership of Oregon (CAPO), Northwest Natural Gas (NWN), and PGE (the Parties) regarding the following:

- PGE's implementation of the Advanced Metering Infrastructure ("AMI") project as set forth in this docket, including the meter purchase and installation contracts provided to the Parties.
- The adoption and implementation of Schedule 111 as filed July 27, 2007, by PGE in direct testimony (Exhibit 202).
- The Conditions to address various concerns and issues raised by parties.

Q. What is the basis for the Stipulation?

A. PGE has been working with the Parties for almost two years to evaluate AMI. As part of that process, we have developed a Conditions document (included as Exhibit 101) and financial analysis (included as confidential and non-confidential work papers) to address the concerns and issues raised by the Parties. PGE also developed draft implementation plans for the project and a draft scoping plan related to customer and system benefits. Further, PGE provided to the Parties signed contracts for the purchase and installation of AMI equipment. Based on these documents and analyses, each party to the Stipulation agrees that all issues have been resolved, and they recommend that the Commission adopt Schedule 111 subject to the Conditions document.

Q. Is there any other testimony related to this Stipulation?

A. Yes. Witness Lisa Schwartz also provides supplemental testimony in order to:

- Explain that in future proceedings, Staff and other Parties may raise issues with respect to PGE's recovery of AMI-associated costs, including the prudence of PGE's actions in implementing the AMI project as they might differ from the project description and cost estimates as presented by PGE in this docket.
- Advise that in other proceedings, Staff may raise issues regarding PGE's proposed timing of direct load control programs for residential and small non-residential customers.

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 filed 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 also provided direct testimony regarding AMI in UE 189 (PGE Exhibit 100), which included the following documentation:

- PGE Exhibit 101, an excerpt of PGE's UE 180 direct testimony (PGE Exhibit 800) related to AMI, per agreement between PGE and other parties that any previous UE 180 testimony could be incorporated in this docket to avoid repetition on topics that are not in dispute.
- PGE Exhibit 102, PGE's proposed AMI conditions (i.e., an earlier draft of the Conditions document included as Exhibit 101 to this testimony). The proposed conditions represent AMI-related commitments that PGE will pursue pending OPUC approval and successful deployment of the AMI system. This document

incorporated additional items requested by Staff and other parties in response to PGE's previous AMI filings, including the draft scoping plan.

- PGE 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 for which the AMI system provides a platform that can be used to develop these programs (e.g., demand response, distribution asset utilization, and outage management).

Q. Has PGE updated its financial analysis of the costs and benefits of AMI since filing its direct testimony on July 27, 2007?

A. Yes. These adjustments, however, only relate to the second issue raised by the OPUC Staff in Section III, and discussed in more detail below. These adjustments do not affect the proposed AMI tariff and do not materially affect the net present value (NPV) of the project. PGE's work papers provide the latest electronic spreadsheets with revenue requirement detail of PGE's high-confidence estimate of the costs and benefits related to AMI plus the NPV benefit over the 20-year life of the project.

B. Project Timing

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

A. PGE now projects that it will begin systems acceptance testing by June 2, 2008. PGE will begin full AMI deployment in January 2009 and expects to finish deployment in the third quarter of 2010.

Q. What is the relevance of this timing?

A. This timing is relevant for two reasons – one technical and one regulatory. First, PGE wanted to provide the meter technology vendor (meter vendor) with adequate time to complete its scalability testing and provide host-system software.

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

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 to implement the 2008 AMI tariff change at the same time as the expected SB 408 credit (June 1, 2008). This timing also coincides with the 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 will provide Staff and other parties with adequate time to review AMI documentation.

Q. Has the meter vendor completed any of the targets mentioned above?

A. Yes. The meter vendor completed its scalability testing in September, which allowed PGE to sign contracts with them and the contract meter installer. Staff has reviewed those contracts and requested a reconciliation of the contracts to PGE's financial analysis. PGE provides this reconciliation in response to Staff's fifth issue in Section III, below.

C. AMI Costs and Benefits

Q. What are PGE's current estimates of AMI 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. 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 (now expected to be 2011). Table 2, below, provides a summary of these benefits.

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 PGE described in its Scoping Plan, which was 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

[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.

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 the proposed AMI Conditions document, which as noted above, was included in PGE Exhibit 102 and has been updated and provided as Joint Exhibit 101.

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

A. Based on current estimates of costs and benefits, PGE calculates that over 20 years, the net present value of the project is approximately $33 million net benefit based on operational cost savings only, but has 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.

D. AMI Tariff

Q. Does the Parties' stipulation address regulatory constraints on PGE's recovery of costs associated with AMI?

A. Yes. Under ORS 757.355, PGE can only recover costs associated with facilities that are presently used to provide utility service. Accordingly, PGE designed its tariffs to recover costs associated with the deployment of new metering equipment only after the meters have been installed, to recover the accelerated depreciation of existing metering equipment prior to the retirement of such equipment, and to include O&M savings as the savings are being achieved.

Q. What is the estimated rate impact of the tariff?

A. PGE's proposed tariff reflects approximately $12.9 million for the net annual revenue requirement impact of the AMI system, including accelerated depreciation of the old metering system, and 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.

Q. How was the AMI revenue requirement allocated to each Schedule?

A. PGE allocated the total revenue requirement into the three components listed above: recovery of new metering equipment; accelerated depreciation of existing metering equipment; and O&M savings. The first component consists of the return on and of the new AMI system as well as items such as property taxes. The second component consists of accelerated depreciation of the old meters, return requirements of the old metering system, and other items such as property taxes. The third component is primarily reduced meter reading expenses. PGE 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 in PGE 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 the new AMI system, and $12.5 million (96.7%) relates to the deployment of the new AMI meters.

PGE 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. PGE allocated the $4.1 million of annualized O&M savings based on the final unbundled UE 180 metering revenue requirement allocation. Finally, PGE allocated the annualized $12.5 million associated with the AMI meters based on annualized AMI installed meter costs. Page 2 of PGE 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. For residential customers (Schedule 7), the percentage change in revenue requirements is 1.2%. The percentage change is 1.4% for small nonresidential customers (Schedule 32) and a fraction of 1% for most large customers. See page 3 of PGE Exhibit 201.

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, 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.

Q. Why is the accelerated depreciation of the old meters appropriate?

A. It is appropriate because it completes the process begun in Docket No. UE 115 and the corresponding depreciation study in UM 901, as approved by Commission Order Nos. 01-777 and 00-158. In those dockets, PGE proposed plans for its network meter reading (NMR) system and began the accelerated depreciation of its older meters in anticipation of eventual full deployment. With approval of PGE's AMI proposal, full AMI deployment will be realized and PGE can recover the return of its older meter investment. The AMI project's NPV benefit of approximately $33 million – including the accelerated depreciation costs - demonstrates that the project is economical.

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 recovery of the new system is accomplished by incorporating a six-month lag in recovery of new AMI costs compared to the AMI deployment schedule listed above, and calculating monthly rate base during the deployment period to reflect the limited deployment during 2008 and lagged cost recovery for deployment in 2009 and 2010.

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

A. The recovery of the old meters 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. How will the remaining costs of AMI be recorded after full deployment is complete and the AMI tariff is terminated by year end 2010?

A. Subsequent to 2010, the AMI system will be part of PGE's rate base, similar to all other plant-in-service. At that point, PGE will also be realizing the full operating benefits described above and in PGE Exhibit 101. To reflect these aspects in rates, PGE will need to file a general rate case with a test year later than 2010. Because PGE estimates that the operating benefits will exceed recovery of AMI capital costs beginning in 2012, PGE has agreed to OPUC Staff conditions regarding the timing of a post-2010 general rate case (see "Regulatory Filings" in the AMI Conditions document, Joint Exhibit 101).

III. AMI Settlement – Staff Issues

Q. Have the parties reached agreement on Staff's issues related to the implementation of PGE's AMI proposal?

A. Yes. Joint Exhibit 102 provides a list of final issues addressed in the AMI Settlement Workshop held on October 26, 2007, and discussed below.

Q. What is Staff's first issue?

A. Staff's first issue relates to the treatment of vehicles used for meter reading as AMI is deployed. Specifically, for the vehicles that PGE plans to retire, Staff requests that PGE report the following by October 1, 2010:

1. Net book value (NBV)[2]
2. Date of sale
3. Sales amounts
4. Sales proceeds or losses
5. Salvage value

Q. Does PGE agree to provide this information?

A. Yes.

Q. Has PGE revised its vehicle purchasing strategy as a result of its proposed AMI project?

A. Yes. In 2006, based on the anticipated impact of AMI, PGE revised its vehicle purchasing strategy to: 1) delay the purchase of meter reading vehicles, and 2) review the retention of each vehicle on a case by case basis. These changes will limit the requirement for vehicle replacement and will maximize vehicle salvage. Ultimately, PGE's goal will be to retain

[2] Because PGE uses group depreciation rates for its assets, the NBV of these vehicles will be their estimated NBV based on group depreciation.

and redeploy as many of the newer meter-reading vehicles as possible in the near term and to retire and sell the remaining older vehicles. Finally, PGE's accounting for the vehicle salvage will conform to Commission Order No. 06-581 (Docket UM 1233, PGE's most recent depreciation study) and standard utility accounting treatment (i.e., based on GAAP) for the salvage/retirement of certain assets within a larger asset group.

Q. How do customers benefit from this treatment of meter-reading vehicles?

A. Customers benefit because: 1) the near-term retention and redeployment will result in fewer vehicle purchases, and 2) the vehicle redeployment and salvage will reduce rate base below what it would be absent AMI.

Q. How do you address Staff's second issue?

A. Staff's second issue relates to updates to the AMI financial analysis based on PGE's responses to OPUC Data Request Nos. 104 and 105 (provided as Joint Exhibit 103).[3] In reply, PGE has performed those updates and provides electronic work papers to this testimony that reflect those changes. These work papers, therefore, represent the final estimates for AMI's costs and benefits and the NPV of the project. These updates to the Excel spreadsheet are summarized in Table 1, below:

Table 1.
Final AMI Updates to Confidential Work Papers, "Attachment A"

Category	Data Request No.	Tab in Attachment A	Cell
Present Value of Costs	104	Summary	D9
Present Value of Benefits	104	Summary	D16
NPV Results	104	Summary	D30
NBV of Old Meters	105	Old Meters-NMR	F76

Q. What is the resolution of Staff's third issue?

A. Staff's third issue is mitigating the rate impacts of AMI during the deployment period. As noted above, the proposed effective date of the AMI tariff coincides with the expected

[3] The Attachment referenced in PGE's responses to OPUC Data Request Nos. 104 and 105 is the same as Attachment A included as work papers to this testimony, and hence, is only provided once.

SB408 credit (June 1, 2008). Based on PGE's tax report filed on October 15, 2007, the rate impact of the AMI tariff should be offset, in total, by the tax credit.

Q. Has PGE addressed Staff's fourth issue and all other issues regarding demand response and other customer and system benefits?

A. Yes. PGE previously provided a draft scoping plan that identifies and roughly quantifies additional customer and system benefits not included in PGE's AMI analyses (see PGE Exhibit 103). In addition, PGE has proposed AMI Conditions (included as Joint Exhibit 101) that address Staff's issues regarding operational implementation plans, customer and system benefits (including demand response, information-driven energy savings, distribution asset utilization, outage management, etc.), regulatory filings, and coordination with NWN in the joint meter-reading area. As noted above, Staff's supplemental testimony addresses plans to further investigate in other proceedings the appropriate timing of direct load control programs for residential and small non-residential customers.

Q. Has PGE successfully responded to Staff's fifth issue?

A. Yes. Staff's fifth issue relates to PGE filing work papers to demonstrate that PGE used its signed AMI contracts as the basis for the associated costs in the UE 189 financial models. As part of work papers to this testimony, PGE provides a reconciliation of the prices listed in the final contracts for meter equipment and installation to the associated costs in PGE's AMI financial analysis (also provided as confidential work papers to this testimony, "Attachment A").

IV. AMI Settlement – CAPO Issues

Q. Have the Parties also reached agreement on CAPO's issues related to the implementation of PGE's AMI proposal?

A. Yes. PGE's Conditions document (Joint Exhibit 101) addresses all of CAPO's issues as they relate to low-income customers for the following:

- Remote disconnect/reconnect
- Earlier reconnection than specified in Oregon Administrative Rules
- Customer payment / agency commitment processing
- Limited service delivery
- Leveraging data
- Long-term benefits of AMI functionality
- Pre-paid metering

V. AMI Settlement – Northwest Natural Issues

Q. Have the Parties reached agreement on Northwest Natural's ("NWN") issues regarding PGE's proposed AMI deployment?

A. Yes. PGE's Conditions document (Joint Exhibit 101) addresses all of NWN's issues related to coordination in the joint meter reading area, as follows:

- Quarterly reporting of coordination efforts
- Notification of dissolution of the Joint Meter Reading Agreement
- Notification of significant changes from the operational implementation plans that may affect the joint meter reading area

VI. CUB Issues

Q. Did CUB raise any issues regarding AMI?

A. Yes. First, CUB argues that costs related to PGE's network meter reading (NMR) investment should not be included in the proposed 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, UE 180, Data Request No. 003, part b (provided in Joint Exhibit 104), PGE did not fully implement the NMR system envisioned in UE 115. Instead, the primary NMR vendor suffered business failure, and PGE therefore 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) beginning in 2003 through 2007.

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 NBV 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 NBV 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 (NBV) of existing metering assets. PGE has identified approximately $3.7 million (NBV) in meter investment that will be retained if PGE deploys AMI. These are high-cost meters (for large non-residential customers) that already provide all of the functionality required of AMI meters.

Q. Why do you believe it is appropriate to replace the NMR assets with AMI?

A. Because it is cost effective to do so. The NMR system is more costly and less functional than the systems available today.[4] So, if PGE were to install AMI and not replace the referenced NMR components, O&M costs would be approximately $600,000 higher annually.[5] Capital costs would also increase to keep the NMR components functional. 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. We believe 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. First, these assets are used and useful to meet the requirements of SB1149. Second, these assets have 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 AMI deployment at a

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[4] For example, the NMR power-line-carrier systems do not support interval data collection. The commercial NMR and residential radio frequency systems have either inferior ability or inability to provide outage information. In addition, none of these systems permit over the network firmware revisions to support new services as they are developed.

[5] In 2011, PGE estimates that additional labor costs for network data operations would be approximately $435,000, additional recurring costs for communication back-haul service would be approximately $120,000, and other miscellaneous costs (e.g., support fees and substation electronics maintenance) would be approximately $46,000. See work papers for additional detail.

later date. In PGE's current technology-evaluation and contracting process, this prior experience has enabled PGE to negotiate for significant savings and added functionality.

Q. What do you propose in response to CUB's first issue?

A. We propose that the Commission approve PGE's 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 is CUB's second issue?

A. CUB's second issue relates to the timing of AMI investment. More specifically, CUB has expressed reservations about proceeding with AMI at this time rather than wait until the cost of advanced meters declines further and a meter technology/communications "standard" has been adopted. CUB believes this standard may result in reduced costs or appliance market transformation to allow direct load control of smart appliances.

Q. How do you reply to this concern?

A. First, PGE believes that further significant cost reductions for AMI technology are not likely to occur in the near future. Second, we do not know if or when an AMI "standard" will be adopted. There are many Home Area Network protocols in use today in the U.S., and many more in use abroad. Regardless, it is not necessary to have a utility "gateway" into the customer's premise in order to communicate with the customer's energy-consuming and energy-controlling devices. A utility can use the meter vendor's proprietary system to send signals to and from the customer's premise, and a bridging device at the premise can "talk" to other devices on the property. Further, during and after AMI deployment, PGE will be able to take advantage of the operational benefits and pursue customer and system benefits previously identified. PGE will continue to work with Sensus Metering (PGE's meter vendor) and related vendors to refine capabilities for direct load control and to interact with appliances. As part of this effort, PGE has applied for a federal Department of Energy grant in combination with Sensus Metering and a prominent appliance manufacturer to show the system's capability to interact with smart appliances. This is part of PGE's appliance market transformation project that has been described as a customer and systems related benefit in AMI Conditions, Joint Exhibit 101.

Q. Did CUB raise any other issues?

A. Yes. CUB has also raised the issue of mandatory time-of-use pricing. Specifically, CUB is concerned that PGE's response to OPUC Data Request No. 012, Attachment 012-A (provided in Joint Exhibit 105), indicates that PGE's long-term strategy is to adopt mandatory time-of-use pricing.

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

A. No. Attachment 012-A was 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, PGE 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 (PGE Exhibit 103), PGE 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, these estimated benefits are based on limited voluntary participation. PGE is also aware that any demand response program and associated tariff will only be implemented after being fully reviewed in a public process and authorized by the Commission as just and reasonable.

VII. Parties' Rights in a Future Proceeding on AMI Costs

Q. What other issues have been raised in this proceeding?

A. Parties have noted their concern regarding the ability to address AMI costs and benefits in future rate proceedings.

Q. How do the parties address the issue?

A. The prudence of the decision to proceed with the AMI project will be decided in this docket. PGE acknowledges that all parties have the right in a future proceeding to address AMI costs and benefits, and that the costs and benefits will be subject to a prudence review. To that end, PGE has also included provisions in its Conditions document that specify when general rate cases can be requested subsequent to full deployment, wherein PGE shall bear the burden of proof in such filing, in accordance with ORS 757.210.

VIII. Qualifications

Q. Ms. Owings, please state your qualifications.

A. I am a Senior Utility Analyst in the Rates and Tariffs section of the Electric and Natural Gas Division of the OPUC. Current responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. I have worked at the OPUC since April 2001. From September 1994 to April 2001, I worked for the Oregon Department of Revenue as a Senior Industrial/Utility Appraiser. I was responsible for the valuation of large industrial properties and utility companies throughout the state. I have a professional accounting degree from the Trend College of Business and received my certification from the National Association of State Boards of Accountancy in the Principles of Public Utilities Operations and Management.

Q. Ms. Schwartz, please state your qualifications.

A. I am a Senior Analyst in the Electric and Natural Gas Division of the OPUC, designated as Staff lead for resource planning, competitive bidding and renewable resources for electric utilities. I also provide analysis and recommendations on other electric utility issues including advanced metering, distributed generation, demand response and pricing options. I have worked at the OPUC since May 2002. Before then, I was a policy analyst at the Oregon Department of Energy for more than six years and a research assistant and assistant administrator of the Oregon State University Extension Energy Program for about nine years. I received a B.S. in Environmental Studies from George Washington University and an M.S. in Land Resources from the University of Wisconsin-Madison.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Proposed AMI Conditions
102	Final Issues
103	PGE Responses to OPUC Data Request Nos. 104 and 105
104	PGE Response to CUB, UE 180, Data Request No. 003
105	PGE Response to OPUC Data Request No. 12, Attachment 12-A

Proposed AMI Conditions
November 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 has or 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.
- Filed draft copies of contracts for AMI equipment and equipment installation on July 2, 2007.
- On October 1, 2007 filed signed copies of contracts for AMI equipment and equipment installation, including a redline/strike-out version to highlight differences from 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 direct load control 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 for modifications.

- For CPP programs, six months following the first and second year after participants are first offered the pricing option, file an evaluation report with the Commission including program costs, estimated capacity savings, customer acceptance results, and the Company's recommendations on whether to continue, modify or terminate the programs.

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

In the IRP that PGE filed June 29, 2007, PGE included in its proposed capacity actions all estimated achievable potential firm direct load control[1] by 2012, under the assumption that this will be the achievable, cost-effective potential that can be reached upon implementation of AMI. Specifically, it includes 23-25 MW of mass market direct load control (ie., from air conditioning, water and space heat), and 80 MW of additional Dispatchable Standby Generation (DSG).

PGE has also included 35 MW by 2012 for firm curtailment among large customers, and critical peak pricing (CPP) tariffs, under the same assumptions of being achievable and cost effective.

To achieve this capability by 2012, PGE has set the following targeted schedule.

- Because our large customers have encouraged PGE to develop a dispatchable peak capacity reduction program, and because of the potential for greater MW among fewer customers more quickly than mass market programs, and because they have the requisite metering capability, the Company has under development a curtailment tariff for its largest customer class (1 MW or greater). The tariff will be proposed by year end 2007. The cost effectiveness of such a program will be determined as part of the investigation of the tariff.
- The next highest potential for cost effective firm demand side capacity during peak periods is among the remaining large business customers. To that end, and where the metering is available, the Company will issue a request to providers of peak demand side capacity to provide proposals under a peak capacity purchase agreement. The development of the RFP is underway and expected to be issued in second quarter 2008, with a tariff following when successful responses are apparent.
- PGE is projecting higher peak loads, in part by the increasing rate of central air conditioning among the residential class. The communications capability of the proposed advanced metering infrastructure will facilitate direct control of major residential appliances such as air conditioners and electric water heaters with additional hardware. Initially PGE planned to issue an RFP for mass market demand side capacity to track with the installation schedule of the advanced meters. This turns out to be cumbersome for direct load control providers as they will not be able to efficiently deploy their installation crews across a targeted customer set over a short duration. Even with a full year of meter installations, a provider may connect only 5-10 MW of their committed load, and would possibly take another year to double that. PGE realizes that mass market direct load

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

control providers will respond more favorably to an RFP that is aligned with the AMI deployment schedule, that is, issued just prior to full deployment of the AMI. Therefore, the RFP will be issued eight months prior to the scheduled full installation of the AMI, or approximately first quarter 2010, with a tariff filed by the end of AMI deployment. In addition to the earlier commitment by large customers, this will provide the needed capacity by 2012.

Voluntary Critical Peak Pricing

AMI meters will support 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, examples of possible design parameters, and a sample implementation period. In subsequent discussions the implementation period has since been updated to include a phase for data gathering that was originally omitted.
- 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.
- The Company estimates that a sampling of meter data can be used for the data gathering phase of a proposed program. After the AMI SAT is completed, approximately 50,000 meters, among all customer classes, will be installed, enough to begin data sampling and gathering.
- Two months prior to 50,000 meters scheduled to be installed, or approximately first quarter 2009, PGE will file an experimental CPP tariff. At least two months prior to filing, the Company will provide a draft tariff to OPUC Staff, CUB, ODOE, CAPO and other stakeholders. The Company also will host workshops to explain the proposed program design and provide an opportunity for informal stakeholder comments.
- As PGE develops its CPP program, the company will evaluate the capability of any programmable communicating thermostats and other demand response technologies for use in both price responsive applications for customers and utility direct load control. The Company will discuss its findings in informal stakeholder workshops in advance of tariff filing and include its evaluation in CPP tariff work papers.

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:

- 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 will activate if awarded 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.[2] 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

[2] This condition does not apply in the event the tariff terminates under Special Condition No. 1 in proposed Schedule 111, Exhibit 202 in PGE's direct testimony filed July 27, 2007.

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

PGE Revenue Operations management has had discussions 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 (with a copy provided to NWN) 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.
- Provide preliminary notification of dissolution of the Joint Meter Reading Agreement between PGE and NWN within 30 days of PGE receiving AMI tariff approval from the OPUC and PGE Board approval to move forward with the project.
- Notify NWN no later than 30 days, and as soon as is practicable, of any significant changes from the operational implementation plans that may affect the joint meter reading area.

Community Action Partnership of Oregon (CAPO) and Oregon Energy Coordinators Associations (OECA) Conditions

Discussions between CAPO 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 outline the specific communication requirements that PGE must meet in disconnecting and reconnecting a customer. CAPO and OECA want assurance that PGE's low-income customers understand the rules ahead of their application using AMI Remote Disconnect/Reconnect functionality so that they can proactively seek the assistance they need in paying their utility bills. To assist in educating customers, PGE will:

- In coordination with Community Action Agencies (CAAs), by December 15, 2008, prior to the start of full AMI meter deployment, develop the following training materials:

- Train the trainer materials that CAA personnel could use in their interaction with low income clients,
- General training information that could be provided to low income customers and social service agencies that serve these customers,
- Workshop material that could be delivered by either PGE or CAA personnel.
- Training of CAA representatives to assure their understanding of the need to communicate only completed and authorized commitments to PGE in relation to reconnections.
- Communicate with CAAs their responsibility in meeting contract obligations by providing funds to PGE within 45 days of the commitment date.

Development of this material will take into account the best methods of communication, including DVDs. During the Systems Acceptance Test consideration will be given to testing communications methodologies with low income customers associated with remote disconnect/reconnect.

During the development of these Administrative Rules, PGE outlined plans to assure that reconnections would be done in a timely manner. To assure reconnections are completed in a timely manner, PGE will:

- Where AMI meters with the automatic disconnect/reconnect feature are deployed, PGE will commit to provide same day reconnections when payments are processed at authorized payment locations or commitments are made by CAAs and reconnection requirements are met by 5:00 PM on Monday through Thursday, and by 3:00 PM on Fridays. PGE will establish procedures to facilitate the customer's required reapplication for service.

During the full deployment of meters across PGE's service territory as part of the AMI Project, PGE plans to install approximately 238,000 remote disconnect/reconnect meters in non-owner-occupied residences. Subsequent to the AMI Project deployment, PGE may consider deployment of additional remote disconnect/reconnect meters as part of the general meter replacement activities and not as a specific incremental cost to customers receiving those meters. However, no formal process has yet been defined about how that deployment would be implemented. Prior to implementing a post-AMI Project deployment of remote disconnect/reconnect meters, PGE will:

- Meet with CAPO, CAAs, OPUC Staff, and other interested parties to review the implementation plan, provide sufficient time for review, and address identified concerns.

Leveraging Data

AMI provides for the collection and assembly of AMI interval data for customers that will enable PGE to deliver benefits described in the Information Driven Energy Savings (IDES) portion of this document. To assist CAAs and low-income customers in accessing electricity usage information to manage their electric bills, PGE will:

- As part of the IDES Project, make AMI interval data available and accessible to low income customers and, with customer approval and specific training (developed jointly by PGE and CAPO/CAAs), to CAAs that serve these customers. The timing of this commitment will be driven through the development of specific implementation plans as part of the IDES Project.

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 equivalent access to these new technologies, PGE will:

- Propose critical peak pricing demand response programs as voluntary "opt-in" programs.
- Provide educational information on demand response programs to PGE Customer Service Representatives and CAA representatives so that they can explain to low-income customers the potential risks of higher bills should they choose to participate in such programs but not reduce energy usage at critical times.
- Support local, regional and national policy decisions that would provide the opportunity for low-income customers to have access to "smart" appliances and in-home communications devices providing pricing information if/when they become available in the market. This will enable low-income customers to have the opportunity to use these technologies to lower their energy usage and their bill.

Limited Service Delivery

CAPO and CAAs have expressed an interest in exploring the possibility of providing minimal, lifeline-like electricity service to customers who have been "disconnected". Such a service could entail providing continuous operation of a refrigerator for the safety and stability of a household's perishable food and/or medications and the operation of, for example, a single standard household outlet. Because PGE is also interested in exploration of this possible service after completing the installation of the initial AMI system, PGE will:

- By March 31, 2009, enter into policy discussions with CAPO, CAAs and other interested parties about providing minimal, lifeline-like service to customers who have been "disconnected". Technology discussions will proceed by September 30, 2009 and PGE will assure that technology decisions made by PGE will not preclude the opportunity for consideration of this program.

Pre-Paid Electric Metering

Pre-paid metering is not a program or functionality that will be included as part of the AMI deployment project. While PGE has discussed using the AMI technology to pilot a pre-paid metering program, no decision to proceed has been made. To assure that this potential program is applied appropriately, PGE will:

- Prior to proposing a pre-paid metering pilot program to the OPUC, meet with OPUC Staff, CAAs, CUB, and other parties to explore parameters associated with pre-paid metering.

Status Reporting

To keep all parties informed of activity in addressing the CAPO OECA conditions, PGE will:

- Semi-annually, beginning in April of 2008 and throughout the deployment period, report to CAPO, CUB the OPUC Staff on status of the development and implementation of discussions, materials and trainings related to the low-income (CAPO) conditions.

UE 189 Settlement Conference
October 26, 2007
Issues by Party

A. Staff Issues

1. Staff encourages PGE to sell the remaining 100 vehicles referred to at PGE/100, Carpenter-Tooman/14, in order to reduce rate base and fleet insurance costs. By October 1, 2010, PGE should report the following information to update Staff on PGE's efforts to sell the vehicles:

    a. Net book value
    b. Date of sale
    c. Sales amounts
    d. Sale proceeds or losses
    e. Salvage value

    As a condition of approval of Advice No. 07-08, PGE will move the net book value of the remaining 100 vehicles to non-utility assets beginning January 1, 2011.

2. PGE should file its update to the accelerated writeoff of old meters (PGE's response to Staff Data Request No. 105, Attachment 105-A) which was inadvertently omitted in the company's July 27, 2007, direct testimony.

3. PGE should mitigate rate impacts using deferral balances or other mechanisms.

4. PGE should commit to filing a direct load control tariff for residential and small nonresidential customers prior to full AMI deployment.

5. PGE should file workpapers to demonstrate that the company derived from its final contracts for meter equipment and installation the associated costs in the UE 189 models.

B. CUB Issues

1. PGE should exclude from rates the $4.8 million in accelerated depreciation for Network Meter Reading equipment approved in UE 115.

2. Timing of AMI investment

C. CAPO Issues

1. Remote disconnect/reconnect. CAPO wants more direct involvement in the development of plans that would impact low-income customers, including plans for the future deployment of AMI meters with remote disconnect/reconnect capability.

2. Earlier reconnection than specified in OARs. Remote reconnect should allow faster processing than currently required in OARs, if payment is made during working hours.

3. Customer Payment/Agency Commitment Processing. CAPO would like automatic reconnect for customers who have payment commitments from community action agencies.

4. Minimal electric service for needy customers. AMI meters can have attributes set to allow minimal service for certain customers. CAPO would like this feature where necessary but believes additional guidance would be required so the customers will fully understand the service.

D. PGE Issues

1. Information Driven Energy Savings. Will the information associated with this application be free to all customers or should there be a charge based on it being a competitive service?

October 17, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 189
PGE Response to OPUC Data Request
Dated October 12, 2007
Question No. 104

Request:

Please explain what has changed in PGE's Status Quo case and why (see cell D9 in Summary Tab).

Response:

The change in cell D9 is primarily due to three changes made in the July 27 filling as described below. To summarize these changes, Attachment 104-A compares rows 6-9 of Attachment A, "Summary" tab (see confidential work papers), from the July 27 filing (where cell D9 equals $357 million) and the March 7 filing (where cell D9 equals $343 million).

The July 27 filing reflects the following:

1. Add 2027 net benefits, since the AMI project now starts in 2008 rather than 2007.
2. The present value calculation, cell D9, is based on 20 years of discounted cash flows from 2008 through 2027. For the March 7 filing, cell D9 was based on 20 years of discounted cash flows from 2007 through 2026 plus the costs in 2006.
3. Due to the one-year shift, the end-of-life ramp down of benefits is applied to years 2025, 2026, and 2027; rather than years 2024, 2025, and 2026 in the March 7 filing.

Rows 12-18 of Attachment 104-A apply these changes to the March 7 filing, so that present value amounts (cells D18 and D26) are approximately in agreement. The small difference is explained by other changes in the July 27 filing such as higher costs in the status quo case for fuel costs, a slightly different discount factor, etc.

Even though the present value calculation in cell D9 changes between the March and July filings, the same calculation change was made in D16 for the present value of the AMI case. Consequently, the net present value (NPV) calculation shown in cells D22 and D30 is mostly unaffected by this change because the NPV is based on the difference between the status quo and the AMI case.

October 17, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 189
PGE Response to OPUC Data Request
Dated October 12, 2007
Question No. 105

Request:

Please provide an update to the accelerated write off of existing meters (see tab "old meters" on attachment A of business case).

Response:

Attachment 105-A provides the requested update, which was inadvertently omitted from PGE's July 27, 2007, filing. This adjustment corrects the old meters balance in Attachment A so it is equal to the balance reflected in Attachment B (i.e., AMI revenue requirement, see work papers of July 27, 2007, filing).

Attachment 105-A is confidential and subject to Protective Order No. 07-089 and is provided under separate cover.

July 7, 2006

TO: Jason Eisdorfer
CUB

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to CUB Data Request
Dated June 22, 2006
Question No. 003

Request:

Please identify the following information concerning NMR/AMR expenditures:

a. What was the NMR/AMR revenue requirement approved by the PUC in UE 115 for a 2002 test year? What was the capital expense? What was the O&M?

b. What was the actual amount of NMR/AMR expenditure in 2002? What was the capital expense? What was the O&M?

c. What was the actual expenditure, capital expense, and O&M expense for 2003, 2004, and 2005?

d. How much of the NMR/AMR budget approved by the PUC in UE 115 was refunded to customers in 2002 and 2003 (please provide amounts by year) as an IT capital refund (See Issue S-45 in UE 115 stipulation)?

Response:

a. PGE did not prepare separate revenue requirements for individual projects in the UE 115 proceeding. Attachment 003-A provides a copy of the revenue requirement work paper that lists proposed NMR capital investment in UE 115. Forecasted O&M for NMR in UE 115 is listed in PGE's response to CUB Data Request No. 002, Attachment 002-A, Exhibit 500, page 35.

b. Attachment 003-B provides a list of actual capital and O&M expenditures by NMR job by year for 2002 through 2005. See PGE's response to CUB Data Request No. 007, Attachment 007-A, for a complete summary of NMR capital (1999-2004). Please note that since PGE did not fully implement the NMR system envisioned in UE 115, we implemented other technology solutions to meet the needs of market-based pricing and direct access. These included time-of-use meters for residential and smaller non-residential customers and pager-based meters for our larger commercial and industrial customers. PGE has not attempted to separately identify all these costs.

c. See Attachment 003-B.

d. Attachment 003-C provides a summary of the S-45 refund to customers related to the NMR project for 2002 and 2003.

Advanced Metering Infrastructure

Objective

PGE will design, construct and operate a two-way advanced metering infrastructure (AMI) system that provides a communications and control platform for valued customer services, Company process efficiencies and the collection and use of interval data.

Business Case Summary

Overview

For the past decade, PGE has researched and tested a wide range of advanced metering infrastructure (AMI) technologies with the goal of implementing an automated meter reading system throughout its service territory. To date, PGE has invested $7 million in its head-end Meter Data Consolidator (MDC) and installed 6,800 automated meters in the field to meet the requirements of Direct Access, E-Manager, load research, system planning and high cost-to-read meters. The next step in the evolution of advanced metering at PGE is to implement a systemwide AMI network.

The AMI project is driven by PGE's desire to:

(1) Be more competitive and responsive to customer needs with new and improved services

(2) Achieve operational efficiencies, reduce costs and improve cash flow

(3) Respond to regulatory interest in demand response, direct load control and other programs enabled by AMI

(4) Position PGE with a two-way "intelligent grid" and modernized infrastructure for revenue-cycle business processes

The current AMI system design calls for radio frequency (RF)-based meter technology to be deployed in urban areas (to take advantage of its capability to also read gas and water meters) and powerline (PLC) technology in more rural and dispersed meter routes. During the initial implementation phase, approximately 25,000 AMI meters and related equipment will be deployed to validate functionality promised in the vendor contracts. During the subsequent deployment phase, the remaining 795,000 meters will be exchanged at the rate of approximately 50,000 meters per month. Total capital requirement, excluding AFDC, is $130 million.

Why AMI?

Advanced metering infrastructure, also known as automated meter reading (AMR), is the next important advancement in utility infrastructure. Like PGE, many electric utilities are viewing AMI as an essential component of their business strategies. Well over 36 million units have been sold to electric utilities by an industry whose annual sales have tripled since 1998.[1] One in three utilities has installed or is installing automated metering – and nine electric utilities have deployed at least one million units.

Why the surge in interest in AMI? It is because a two-way AMI system makes it possible for utilities to implement a wide range of services to customers and achieve significant operational efficiencies. With an advanced metering system, PGE will be able to implement:

- New time-varying rates (TVRs) in the meter without sending a meterman to the site
- Customer-selected billing due dates
- Premise monitoring and smart appliance services
- Customer access to daily usage data
- Remote, on-command meter reads
- Remote meter disconnects/reconnects
- Improved energy theft detection
- Improved outage detection and restoration
- Cost-effective demand response and direct load control programs

Positioning for the Future

Two-way AMI systems are increasingly recognized by the industry and regulators as the platform that best positions a utility to meet customer needs and societal goals. For instance, the Province of Ontario recently ruled that all customer meters are to be fully two-way enabled by 2010 to support the reduction of coal-fired generation. Meanwhile, California is marching toward an AMI decision that would enable most or all meters to support pricing and demand response options. As part of this effort, in June 2005 PG&E announced its intent to install 9.3 million meters over the next 5 years. And, equally important, the Oregon Public Utility Commission (OPUC) staff is encouraging demand response programs as well.

The high interest in demand response by regulators is due in part to the low asset utilization that has characterized the electric utility industry from its inception. Electric utilities operate at about 50% asset utilization. By comparison, asset utilization in refineries, chemical plants, pulp and paper mill, steel plants, etc., all run at 95%+. Other industries meet their "obligation to serve" not by building rarely used production capacity, but by charging higher prices when supply is low. Electricity is one of the few products whose prices do not vary with market demand.

[1] "AMR Deployments in North America", 8th Edition, Howard A. Scott, Ph.D., Cognyst Consulting LLC, April 2004.

Two-way AMI is the means that allows PGE to measure usage during specific, but not pre-determined periods of low supply or high demand. With the ability to measure comes the ability to use price as the means to alleviate supply-demand imbalance. With additional hardware at specific appliances, this same network allows PGE to aid both the customer and the Company by reducing load automatically during high price periods. A one-way AMI system does not create these capabilities cost effectively.

PGE's vision of a "smart grid" – one that provides a means for PGE to work with its customers to economically flatten and lower the demand curve – depends ultimately upon a two-way flow of electrons and a two-way communications capability.

AMI Benefits

Based on the experience of utilities that have implemented full-system AMI, a wide range of benefits can result from a well-conceived and executed AMI program where the capabilities of the technology are leveraged throughout the organization.

Customer Benefits

For 115 years, the once-a-month meter read has been the prime basis for charging customers for the product and for customers to understand their energy use. Old meter technology limits access to information and limits pricing options.

Through AMI, the following specific benefits and services will be available upon project completion:

- Customers will be able to select preferred bill due dates for their bills.
- Customers will be able to take advantage of new pricing structures such as critical peak pricing.
- There will be fewer estimated bills and more accurate electricity bills.
- Customers closing their PGE accounts can be given final bill amounts over the phone because CSRs will be able to perform final reads from their workstations without having to send out a meter reader for a special read.
- Customers can obtain hourly usage graphs within two (2) days after use.
- CSRs will have immediate access to a customer's actual daily usage to help explain or resolve high bill complaints.
- CSRs will have a means to query a meter to identify whether a customer outage is a PGE problem or possibly an internal problem for the customer.
- There will be fewer property damage, personal safety and injury, and privacy issues because PGE will not have to visit customer meter locations on a monthly basis.

Company Benefits

In addition to the direct benefits that customers will see, the recommended AMI system will provide overall benefits to PGE that will be passed on to customers and shareholders because of the increased operating efficiency and lower operating costs that result from AMI.

These benefits include:

- Elimination of 99% or more of manual meter reads and the resulting workforce reduction savings
- Substantial reduction in the number of service orders and field dispatches for special reads
- Process improvements and cost reductions across a wide range of operations, including system planning, distribution, asset management, substation services, load research, customer service and outage management
- Remote disconnect/reconnect capability
- Expansion of PGE's ability to collect and utilize interval data for planning purposes
- The ability to perform more detailed load forecasting, customer segmentation studies and marketing analyses
- Increases in the level of energy theft detection and revenue recovery
- Reduced employee injuries in the field and decreased number of vehicle accidents
- Less environmental damage
- Future reduction in wholesale costs from a price-based demand response program

Long-term Benefits

The most significant long-term economic benefit of AMI is to improve PGE's asset utilization of generation and transmission resources. Over the long term, it should be possible to increase capacity utilization from 50% to about 65% as customers respond to price changes the way they do with other products.

A possible step toward increased utilization has been modeled by examining variations of an opt-out, critical peak pricing (CPP) scenario. PGE estimates that the NPV benefit could range between $4 million and $34 million. These benefits were not included in the financial model because the timing and form of implementation of demand response is uncertain at this time. Demand response, however, is an important subject because the OPUC is interested in moving forward to build this capability in Oregon investor-owned utilities (IOUs).

As additional premise technology develops, the AMI system will allow PGE to send control signals to the premise that enable the following additional capacity benefits: load flattening everyday peaks with short-duration water heater, air-conditioner, clothes dryer or refrigerator control; extended-outage restart assistance; and small-unit (<15KW) distributed generation command, control and telemetry support.

Project Financials

A "base case" AMI project future was modeled against a "status quo" future (i.e., business as usual). Table 1-1 shows the NPV of the difference in revenue requirements between these two futures. For the base case, the AMI system was modeled on the assumption of providing operational value for 20 years. This is considered to be a realistic case.

TABLE 1-1. FINANCIAL RESULTS

AMI Business Case as Modeled	Results
Capital Investment	$130 million
Annual O&M Savings (2010)	$20 million
Net Present Value (20 years)	$30 million
Demand Response Case Study (outboard)	**Results**
Demand Response Benefit (NPV)	adds $4 to $34 million

Because of the significant benefits that are achieved with a positive financial impact, the AMI Project Team is proposing a two-way, integrated radio frequency/powerline carrier network to blanket the PGE service territory.

Capital Requirement

The incremental capital requirement for the AMI project is approximately $130 million (excluding AFDC). AMI meters represent the bulk (79%) of the capital cost (see Table 1-2).

TABLE 1-2. AMI CAPITAL COST BREAKOUT

Project Element	Cost ($ millions)	% of Total
RF Meters	$ 81.9	63%
PLC & Phone Meters	20.5	16%
Meter Installation (loaded)	8.5	7%
Project Management (loaded)	4.7	3%
Systems Development (loaded)	5.1	4%
PLC Equipment	3.5	3%
All Other Costs	5.4	4%
TOTALS	**$129.6**	**100%**

Project Benefits & Savings

Major O&M drivers in the financial results are: (1) reduced labor costs for meter reading, field collection reps and customer service, (2) reduced working capital requirement, (3) a reduction in unaccounted for energy (UFE) loss, and (4) an increase in late payment revenue.

In the first stable year after AMI implementation (2010), there will be a net reduction in 144 employees – meter reading (114 FTE), field collection operations (22 FTE), billing center (13 FTE) and revenue operations (4 FTE). Several RCs will show an increase of a total of 9 FTE. Annual O&M costs, including direct and support labor and overheads, will be reduced by about $20 million.

An Employee Transition Plan is being developed with the goal to retain and train as many affected employees as possible for other positions within PGE and to provide transition support for employees who seek outside employment opportunities. Severance will be offered to those employees who are eligible and who are not retained within the Company.

Project Risks & Sensitivities

The following section discusses the most probable risks to project performance and contains a rough estimate of the potential financial impacts. Following the risk discussion are a number of sensitivities that are the result of specific case runs in the model.

Risks

With a project of this magnitude, risk identification and mitigation is a crucial component of project planning and implementation. Expanded detail is found in the full Business Case.

The most significant risks are summarized in Table 1-3.

TABLE 1-3. MAJOR PROJECT RISKS

Risk	Impact on NPV ($ million)	Mitigation Actions	Probability[1]
Early Onset of High Failure Rate of Premise Hardware	$ (22)	Contract specifications and warranties; field experience	1-5%
Failure or Significant Problems with CIS Data Exchange Automation	(5.0)	Current project is funded and underway; thorough testing prior to deployment	1-5%
MDC Scaling Problems During Full Deployment	(10.0)	Implement multi-threading input/output; upgrade to larger server when exceeding 80% of capacity	1-5%
2-Year Delay in Implementing Customer-Selected Due Date	(6.0)	Establish as high IT priority; thorough planning, testing and implementation	1-5%
Delay in Implementing Remote Disconnect Capability	(5 - 8)	Acquire key internal/external stakeholder approvals; manual workarounds available	5-10%
Communication Server Scalability	(10)	Upgrade to larger server or add server; SAT testing before and after deployment; contract terms and penalties	1-5%
Insufficient Internal Communication & Coordination	(15)	Work closely with IT and other internal teams for project implementation oversight; prioritize work priorities on department and corporate scorecards	1-5%

[1] Likelihood of occurrence after mitigation actions are taken

Mitigation for each of the major risks listed above as well as for other project risks that have been identified (see *Appendix 5-2*). The Project Team believes that all project risks can be mitigated sufficiently to ensure that the project achieves its operational and financial objectives.

A full end-to-end test of all critical scale-up processes – to make sure that all systems are working successfully – will be undertaken before full deployment is initiated. The decision to move forward to seek final PGE Board approval will be made after consultation with the AMI stakeholders and approval from the AMI Policy Committee.[2]

Sensitivities

Project NPV is most sensitive to the failure rate of the meters. This, in turn, determines the technical project life. The base case assumes that 35% of the meter modules fail over a project life of 20 years. The economics do not include the cost of the replacement project but do ramp down the net benefits of this project accordingly. The economics include the write-off of all undepreciated assets at the end of 20 years. All appropriate maintenance costs are included for the full 20 years. These assumptions produce an NPV of nearly $30 million.

Table 1-4 shows the sensitivity to the base case above. An early onset of a high meter failure rate is the basis for the conservative case. The assumptions are the same as the base case except that all end-of-project tasks begin 5 years sooner. This is a conservative assumption. The optimistic case assumes full benefits through year 20 with cumulative meter failures of less than 12%. This may be possible with today's electronic manufacturing experience, but this is considered optimistic.

TABLE 1-4. SENSITIVITY OF METER LIFE

Meter Life Assumption	Project NPV ($ millions)
Conservative Case – 15-Year Life	$ 8
Base Case – 35% Failure Rate at 20 Years	30
Optimistic Case – Modest Failure Rate at 20 Years	50

Other key sensitivities have been modeled and the impact on project NPV calculated, as show in Table 1-5.

TABLE 1-5. SENSITIVITY ANALYSIS

Sensitivities	Impact on NPV ($ millions)
Double IT Capital Costs	$ (10.5)
Reduce Working Capital Savings by 50%	(6.7)
1-Year Delay on Project Benefits (RC 452 only)	(4.1)
3-Month Delay on Workforce Reduction (RC 451 only)	(2.5)
+/- 10% on All Capitalized Labor	+/- 2.3
+/- 5 FTEs in O&M Labor (2005-2008)	+/- 2.3
+/- 10 FTEs for Entire Project Life	+/- 10.7
+/- 5% on All Meter Prices	+/- 7.2

[2] The AMI Policy Committee consists of Jim Piro, PGE Executive Vice President and CFO, and PGE Vice Presidents Steve Hawke and Pamela Lesh.

Implementation Plan

Successful AMI deployment requires considerable diligence from initial planning and analysis through process and business change. The AMI Project Team plans a staged deployment with rigorous system acceptance tests (SATs) and off-ramps at critical mileposts if the project is not meeting its cost and operational goals. Commitment of capital will be staged correspondingly.

The major tasks of AMI implementation are as follows:

Phase I: Project Readiness

- **IT Requirements.** Following from the IT work plan already completed, the development of detailed requirements will be undertaken in Phase I to scope and cost out all IT development and enhancement projects needed to successfully implement AMI.
- **Vendor RFP.** A competitive bidding process will be undertaken in Phase I. Bid documents will require that AMI vendors demonstrate successful track record in previous deployments and the ability to meet PGE's technical specifications. The RFP process will substantiate the budgetary estimates in the business case and validate that vendors are willing to mitigate key risks.
- **OPUC Review.** The AMI project plan and business case will be presented to the OPUC concurrent with or as part of the Company's 2007 general rate case filing. The Company will work with OPUC staff to develop a rate treatment approach that minimizes the price impact to customers. The project will not proceed without satisfactory recovery and minimal rate impact.

Capital requirement for Phase I is $3 million.

Phase II: Verification & Testing

- **Technology and Scalability Testing.** Rigorous testing of internal and vendor systems will be conducted to demonstrate the acceptability of hardware, software and system interfaces. All hardware, software and critical interfaces must test successfully at operational levels before full deployment will be initiated.
- **Contract Negotiations**. Negotiations to establish the final costs, terms and conditions for hardware and software will be carried out by an internal team representing various PGE work groups. All deliverables will be clearly specified with warranties and/or penalties for failure to meet timelines or specifications. Contracts will contain stipulations that limit the Company's commitment subject to conditions, such as satisfactory OPUC action, acceptable performance in the vendor SATs and final Board approval.
- **OPUC Approval**. OPUC approval of AMI and cost treatment (acceptable to PGE) will need to be in place prior to committing to full implementation.

Capital requirement for Phase II is estimated to be $4 million.

Phase III: Full Implementation

Subject to successful completion of Phase I and II activities, the AMI team will request funding from the Board in late 2006 or early 2007 to complete the AMI Project. Phase III entails the following major activities:

- **NDO/Backoffice Ramp-up.** The Company's Network Data Operations (NDO) and IT groups will scale up the currently operational Meter Data Consolidator (MDC), then test and implement the interfaces necessary for high-volume data exchange to and from PGE's enterprise systems.
- **Business Process Change.** A systematic business process review is under way. Priority is being given to processes needed to implement AMI and processes needed to achieve the benefits modeled. In Phase III, an interdepartmental project will be created to coordinate and implement the approved business process changes.
- **Full Deployment.** Full meter deployment and purchase commitments will be initiated only after satisfactory regulatory action and successful completion of SATs on all critical applications, interfaces and hardware. Detailed project manuals and quality control (QC) measures will guide field activities to ensure that project mileposts and budgets are met. The Company already has considerable experience installing and testing AMI meters and communications equipment.

Capital requirement for Phase III is estimated to be $123 million.

The overall project timeline is shown in Table 1-6, including the 2003 implementation of the MDC, which is now the system of record for all PGE meter reads.

TABLE 1-6. AMI PROJECT SCHEDULE

TIMELINE	2003				2005				2006				2007				2008			
AMI PROJECT ACTIVITY	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Meter Data Consolidator (MDC)																				
PGE Board Approvals																				
Phase I – Project Readiness																				
Phase II – Verification & Testing																				
Phase III – Full Deployment																				

Planning/Testing
Implementation

Moving Forward

The AMI Project Team currently seeks Board approval for Phase I of the AMI project as described in this business case.

Following Board approval, the following actions will be taken in accordance with the business plan:

- Continue to work with PGE's Rates & Regulatory Affairs department to obtain OPUC project approval, supportive regulatory treatment and to minimize price impact on customers
- Work closely with internal stakeholders to guide IT planning and business process change
- Issue an RFP to leading vendors of PLC and RF systems
- Develop a detailed IT work plan and begin such work as required to mitigate project risk or to start application development, if required, to effect production status of these applications before October 2008
- Create an AMI Project Profile and accounting ledgers as required per corporate governance
- Carry out detailed planning for employee transition, external and internal communications, business process improvement and organizational change management

Conclusion & Recommendations

Advanced metering is one of the single largest capital investments – and arguably one of the biggest leaps forward – in distribution operations, asset management, customer service and billing to be considered by the Company in many decades.

The positive business case for AMI goes well beyond the numbers. Implementation of AMI ushers in a new era for PGE, bringing with it the capability to not only significantly reduce operating costs, but also to be more responsive to customer needs and deliver greater value to all of our stakeholders.

AMI technology enables the Company to:

- Redesign key business processes in nearly all aspects of utility operations, giving us new capabilities to better serve our customers.
- Deliver data on the daily usage of our product, giving both the Company and customers a rich understanding of how to manage energy use and system assets in a more cost-effective way.
- Create a new technology platform for the delivery of innovative, value-added products and services to customers.

The AMI Project Team is therefore pleased to submit this business case to the PGE Board. We recommend that the Board authorize the Company to move forward with the $3 million Phase I of the AMI Project.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **STIPULATION (INCLUDING CONDITIONS) AND JOINT DIRECT TESTIMONY AND EXHIBITS IN SUPPORT OF STIPULATION (JOINT/100-105)** 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 21st day of November 2007.

Cece L Coleman

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