Portland General Electric Company
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Pamela Grace Lesh
Vice President
Regulatory Affairs & Strategic Planning

March 7, 2007

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol Street, N.E., Suite 215
Salem, OR 97301-2551

RE: Advice No. 07-08, Advanced Metering Infrastructure (AMI)

In addition to the electronic filing, enclosed is the original, with a requested effective date of **June 6, 2007:**

First Revision of Sheet No. 1-1
First Revision of Sheet No. 1-2
First Revision of Sheet No. 100-1
Original Sheet No. 111-1
Original Sheet No. 111-2
Original Sheet No. 111-3

This filing adds Schedule 111, an adjustment schedule that collects costs related to the deployment of AMI, which is a metering system that allows two-way communications between the meter and PGE. AMI will replace most of PGE's meters within the Company's service territory.

Part A of Schedule 111 will begin collecting the accelerated depreciation of meters that AMI will replace. Beginning January 1, 2008, Part A will also collect the revenue requirement impact of installed AMI facilities less operation and maintenance (O & M) cost savings.

Part B of this schedule credits customers the money for Independent Spent Fuel Storage (ISFS) tax credits for prior tax years deferred in accordance with Order No. 06-117. As a result of Part B, customers will not experience a Schedule 111 net rate impact until the Part B credit terminates this credit effective December 31, 2007.

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

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

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

PGE's proposed tariff will reflect approximately $13.4 million for the estimated annual revenue requirement impact of the AMI system, plus accelerated depreciation of the old metering system, less O&M savings during the deployment period. This represents an approximate 0.8% increase on PGE's revenue requirement as determined by OPUC Order No. 07-015 in PGE's last general rate case, Docket UE 180. The annual revenue requirement impact, by year, by component, is listed in Table 1.

The revenue requirement assumes the following timing and cost recovery components:

- Systems acceptance testing (SAT) begins in July 2007.
- SAT is completed by year end 2007.
- Full AMI deployment begins in February 2008.
- AMI deployment is completed in September 2009.
- The AMI tariff becomes effective July 1, 2007. All revenue requirements for 2007 were calculated at half-year values so that when annualized, they would correspond to the $13.4 million impact.

Table 1. AMI Annual Revenue Requirement Impact, By Year, By Component

	2007	2008	2009
Old Metering System			
Accelerated depreciation of old meters/system	14,620	15,973	7,225
Return on old meters/system (after tax)	2,094	1,219	329
Other RevReq of old system (e.g., property and other taxes, etc.)	3,802	1,116	357
Net revenue requirement on old system	20,516	18,308	7,911
New AMI			
O&M Savings	-	(415)	(1,354)
Return on AMI (after tax)	-	582	4,519
Other RevReq of new system (e.g., return of, property taxes, etc.)	-	1,989	9,217
Net revenue requirement on new system	-	2,156	12,383
Total revenue requirement impact of AMI	20,516	20,464	20,294
Status Quo Offset			
Return on status quo metering system (after tax)	2,253	2,224	2,162
Return of status quo metering system	3,303	3,310	3,247
Other RevReq of old system (e.g., property and other taxes, etc.)	1,562	1,531	1,489
Net revenue requirement on status quo system	7,119	7,065	6,898
Net revenue requirement impact	13,397	13,399	13,396

Because the proposed tariff involves a complex project with long-term implications, PGE requests that the Commission assign a docket number and establish a formal proceeding to more fully address the issues related to AMI. In support of that proceeding PGE submits the following documentation:

- Excerpts from PGE's UE 180 direct testimony related to AMI. PGE proposed the AMI project in UE 180 but PGE delinked AMI from the rate case with the provision that previously filed AMI testimony could be included in any subsequent AMI docket. PGE submits the attached testimony to provide a summary of the project and explain its costs and benefits.
- Most recent high-confidence cost estimate. Because AMI-related costs have been updated since the original filing, we are including electronic spreadsheets with revenue requirement detail of our most recent high-confidence cost estimates and net present value benefit over the 20-year life of the project. PGE currently estimates that the project's capital costs will be approximately $130.1 million, that annual O&M savings will be approximately $16.0 million in the year following full deployment, and the net present value benefit is approximately $17.6 million. The updated revenue requirement incorporates a six-month lag in any recovery of the capital carrying cost of the new system to avoid any conflicts with ORS 757.355. The only changes to the current financial analysis, as submitted on February 9, 2007, are updates to O&M as follows:

- Decrease status quo O&M in 2008 through 2010 by approximately $600,000 per year to reflect project management costs that are not reflected in PGE prices or revenue requirement filings for this period.
- Increase AMI O&M for July through December 2007 and reduce O&M for July through December 2010 by approximately $1.0 million. This amount reflects project management costs that are effectively included in the revenue requirement for each six-month period from 2008 through 2010 but: 1) are applicable prior to deployment during the second half of 2007, and 2) do not apply to the project subsequent to deployment during the second half of 2010.

- PGE's proposed AMI conditions. The proposed conditions represent AMI-related commitments that PGE will pursue pending OPUC approval and successful deployment of the AMI system. This document incorporates all additional items request by the OPUC Staff and other parties in response to PGE's draft scoping plan.
- PGE's scoping plan. The scoping plan identifies and roughly quantifies additional customer and system benefits not included in PGE's original UE 180 filing. These benefits are derived by programs that the AMI system supports or provides a platform for developing (e.g., demand response, grid management, and outage management). PGE provided a draft copy of this document on December 21, 2006.
- Motion for protective order. Because some unit-cost figures in PGE's AMI financial analysis relate to items still under negotiation and protected by confidentiality agreements with vendors, one electronic file will be provided subject to the protective order.
- Work papers of the Part A rate spread and work papers showing the distribution of the Part B credit.

This filing also revises the Table of Contents and Schedule 100, Summary of Applicable Adjustments to include Schedule 111.

Should you have any questions or comments regarding this filing, please contact Alex Tooman at (503) 464-7623 or Jennifer Busch at (503) 464-8854.

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

Sincerely,

R Dahlgren
for

/s/ Pamela G. Lesh
Vice President, Regulatory Affairs & Strategic Planning

Enclosures
cc: Service List – UE 180, 181 and 184

PORTLAND GENERAL ELECTRIC COMPANY
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RATE SCHEDULES

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

APPLICABLE ADJUSTMENT SCHEDULES

(N)

Schedules	102	105	106	107	108	111	115	125	126	128	129	130
	(1)		(1)		(3)			(1)		(4)	(1)	(1)
7	x	x	x	x	x	x	x	x	x			
9				x	x	x	x					
15	x	x	x	x	x	x	x	x	x			
32	x	x	x	x	x	x	x	x	x	x		
38	x	x	x	x	x	x	x	x	x	x		x
47	x	x	x	x	x	x	x	x	x			
49	x	x	x	x	x	x	x	x	x			
75	x$^{(2)}$	x$^{(2)}$	x	x$^{(2)}$	x	x	x	x$^{(2)}$	x$^{(2)}$	x		
76R	x	x	x	x	x	x	x					
83	x	x	x	x	x	x	x	x	x	x		x
87	x$^{(2)}$	x$^{(2)}$	x	x$^{(2)}$	x	x	x	x	x$^{(2)}$			
89	x	x	x	x	x	x	x	x	x	x		x
91		x	x	x	x	x	x	x	x	x		
92		x	x	x	x	x	x	x	x			
93		x	x	x	x	x	x	x	x			
94		x	x	x	x	x	x	x	x			
483	x	x	x	x	x	x	x		x$^{(5)}$		x	
489	x	x	x	x	x	x	x		x$^{(5)}$		x	
515	x	x	x	x	x	x	x		x$^{(5)}$	x		
532	x	x	x	x	x	x	x		x$^{(5)}$	x		
538	x	x	x	x	x	x	x		x$^{(5)}$	x		x
549	x	x	x	x	x	x	x		x$^{(5)}$	x		
575	x$^{(2)}$	x$^{(2)}$	x	x$^{(2)}$	x	x	x		x$^{(2)}$	x		
576R	x	x	x	x	x	x	x					
583	x	x	x	x	x	x	x		x$^{(5)}$	x		x
589	x	x	x	x	x	x	x		x$^{(5)}$	x		x
591		x	x	x	x	x	x		x$^{(5)}$	x		
592		x	x	x	x	x	x		x$^{(5)}$	x		
594		x	x	x	x	x	x		x	x		

(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily or Monthly pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 483 and 489).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 111
ADVANCED METERING INFRASTRUCTURE

PURPOSE

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

APPLICABLE

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

PART A

From July 1, 2007, through December 31, 2009, Part A collects from Customers the revenue requirement impact of accelerated depreciation of the meters that AMI will replace. After December 31, 2007, Part A also collects the revenue requirement impact of newly installed AMI less O & M savings.

PART B

Part B refunds to Customers Independent Spent Fuel Storage (ISFS) tax credits for prior tax years.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after July 1, 2007, will be:

Schedule	Part A	Part B	Adjustment Rate	
7	0.121	(0.121)	0.000	¢ per kWh
15	0.045	(0.045)	0.000	¢ per kWh
32	0.105	(0.105)	0.000	¢ per kWh
38	0.058	(0.058)	0.000	¢ per kWh
47	0.345	(0.345)	0.000	¢ per kWh
49	0.083	(0.083)	0.000	¢ per kWh
75				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh

SCHEDULE 111 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
76R				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
83				
Secondary	0.026	(0.026)	0.000	¢ per kWh
Primary	0.019	(0.019)	0.000	¢ per kWh
87				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
89				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
91	0.040	(0.040)	0.000	¢ per kWh
92	0.018	(0.018)	0.000	¢ per kWh
93	0.186	(0.186)	0.000	¢ per kWh
94	0.018	(0.018)	0.000	¢ per kWh
483				
Secondary	0.026	(0.026)	0.000	¢ per kWh
Primary	0.019	(0.019)	0.000	¢ per kWh
489				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
515	0.045	(0.045)	0.000	¢ per kWh
532	0.105	(0.105)	0.000	¢ per kWh
538	0.058	(0.058)	0.000	¢ per kWh

SCHEDULE 111 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
549	0.083	(0.083)	0.000	¢ per kWh
575				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
576R				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
583				
Secondary	0.026	(0.026)	0.000	¢ per kWh
Primary	0.019	(0.019)	0.000	¢ per kWh
589				
Secondary	0.019	(0.019)	0.000	¢ per kWh
Primary	0.016	(0.016)	0.000	¢ per kWh
Subtransmission	0.015	(0.015)	0.000	¢ per kWh
591	0.040	(0.040)	0.000	¢ per kWh
592	0.018	(0.018)	0.000	¢ per kWh
594	0.018	(0.018)	0.000	¢ per kWh

TERM

Part A collections made under this adjustment schedule will terminate December 31, 2009. Part B credits will terminate December 31, 2007.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE _____

In the Matter of Advice No. 07-08, Advanced Metering Infrastructure (AMI) filed by PORTLAND GENERAL ELECTRIC COMPANY	**MOTION FOR APPROVAL OF PROTECTIVE ORDER**

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company ("PGE") requests the issuance of a Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect confidential market information and confidential business information, plans and strategies. In support of this Motion, PGE states:

1. Concurrent with the filing of this Motion, PGE has filed Advice No. 07-08 to add Schedule 111, an adjustment schedule related to the deployment of an Advanced Metering Infrastructure ("AMI").

2. Some of the work papers supporting the advice filing contain confidential information regarding expected prices for AMI related equipment and services. Final contract terms have not been agreed to and disclosure of this information could hinder PGE's ability to negotiate. PGE is also obligated by a non-disclosure agreement to keep certain information confidential. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

3. PGE would like to file with the Commission and provide to interested parties a complete set of work papers as soon as possible, and requests expedited consideration of this motion.

4. PGE also anticipates that parties participating in this docket may make further requests for confidential information. PGE further anticipates it will be required to file periodic updates containing confidential information in this proceeding.

5. While PGE desires to provide parties with requested information, the information is of significant commercial value, and its public disclosure could be detrimental to PGE and its customers.

6. The Commission should therefore issue a Protective Order to protect the confidentiality of that material. The requested order, identical to the one that the Commission customarily issues, is attached.

For the reasons stated above, PGE requests that a protective order be issued in this proceeding.

DATED this 7th day of March, 2007.

Respectfully submitted,

/S/ DOUGLAS C. TINGEY

Douglas C. Tingey, OSB No. 04436
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Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8926 phone
(503) 464-2200 fax
doug.tingey@pgn.com

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE ____

In the Matter of Advice No. 07-08, Advanced Metering Infrastructure (AMI) filed by PORTLAND GENERAL ELECTRIC COMPANY	**ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On March 7th, 2007, Portland General Electric Company ("PGE") filed a Motion for a Protective Order with the Public Utility Commission of Oregon ("Commission"). PGE states that good cause exists for the issuance of such an order to protect confidential business information, plans and strategies. Specifically, PGE states that some of the work papers supporting Advice No. 07-08 contain confidential information regarding expected prices for Automated Metering Infrastructure related equipment and services that are still being negotiated, and information PGE is contractually obligated to keep confidential. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

Pursuant to OAR 860-012-0035(1)(k), I find that good cause exists to issue a Protective Order, attached as Appendix A. Under the terms of the order, a party may designate as confidential any information that falls within the scope of ORCP 36(C)(7).

Confidential information shall be disclosed only to a "qualified person" as defined in paragraph 3 of the Protective Order. Authors of the confidential material, the Commission or its Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" who may review confidential information. Other persons desiring confidential information must become qualified pursuant to paragraph 10.

To receive confidential information, however, all parties—with the general exception of Staff—must sign the Consent to be Bound Form attached as Appendix B. This includes the party seeking the issuance of the protective order, because any party may designate information as confidential under this order.

The confidentiality of confidential information shall be preserved for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality.

All persons who are given access to confidential information have the duty to monitor their own conduct to ensure their compliance with the Protective Order. Such persons shall not use or disclose the information for any purpose other than the preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the confidential information secure. If any questions exist as to the status of any person to receive confidential information, the parties may contact the Administrative Hearings Division at (503) 378-6678.

ORDER

IT IS ORDERED that the Protective Order, attached as Appendix A, shall govern the disclosure of confidential information in this case.

Made, entered, and effective on ____________________________.

____
[Judge]
Administrative Law Judge

A party may appeal this order to the Commission pursuant to OAR 860-014-0091.

PROTECTIVE ORDER

DOCKET NO. UE ___

Scope of this Order-

1. This order governs the acquisition and use of "Confidential Information" in this proceeding.

Definitions-

2. "Confidential Information" is information that falls within the scope of ORCP 36(C)(7) ("a trade secret or other confidential research, development, or commercial information").

3. A "qualified person" is an individual who is:

   a. An author(s), addressee(s), or originator(s) of the Confidential Information;

   b. A Commissioner or Commission staff;

   c. Counsel of record for a party;

   d. A person employed directly by counsel of record; or

   e. A person qualified pursuant to paragraph 10. This includes parties and their employees.

Designation of Confidential Information-

4. A party providing Confidential Information shall inform other parties that the material has been designated confidential by placing the following legend on the information:

CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER

To the extent practicable, the party shall designate as confidential only those portions of the document that fall within ORCP 36(C)(7).

5. A party may designate as confidential any information previously provided by giving written notice to the other parties. Parties in possession of newly designated Confidential

Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

Information Given to the Commission-

6. Confidential Information that is: (a) filed with the Commission or its staff; (b) made an exhibit; (c) incorporated into a transcript; or (d) incorporated into a pleading, brief, or other document, shall be printed on yellow paper, separately bound and placed in a sealed envelope or other appropriate container. An original and five copies each separately sealed shall be provided to the Commission. **Only the portions of a document that fall within ORCP 36(C)(7) shall be placed in the envelope/container**. The envelope/container shall bear the legend:

> THIS ENVELOPE IS SEALED PURSUANT TO ORDER NO. ________ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

7. The Commission's Administrative Hearings Division shall store the Confidential Information in a locked cabinet dedicated to the storage of Confidential Information.

Disclosure of Confidential Information-

8. Parties desiring receipt of Confidential Information shall sign the Consent to be Bound Form attached as Appendix B. This requirement does not apply to the Commission staff. Confidential Information shall not be disclosed to any person other than a "qualified person," as defined in paragraph 3. When feasible, Confidential Information shall be delivered to counsel. In the alternative, Confidential Information may be made available for inspection and review by qualified persons in a place and time agreeable to the parties or as directed by the Administrative Law Judge.

9. Qualified persons may disclose confidential information to any other qualified person, unless the party desiring confidentiality protests as provided in Section 11.

10. To become a qualified person under paragraph 3(e), a person must:

    a. Read a copy of this Protective Order;

    b. Execute a statement acknowledging that the order has been read and agreeing to be bound by the terms of the order;

    c. Date the statement;

d. Provide a name, address, employer, and job title; and

e. If the person is a consultant or advisor for a party, provide a description of the nature of the person's consulting or advising practice, including the identity of his/her current, past, and expected clients.

Counsel shall deliver a copy of the signed statement including the information in (d) and (e) above to the party desiring confidentiality and to all parties of record. Such notification may be made via e-mail or facsimile. A person qualified under paragraph 3(e) shall not have access to Confidential Information sooner than five (5) business days after receipt of a copy of the signed statement including the information in (d) and (e) above by the party desiring confidentiality.

11. All qualified persons shall have access to Confidential Information, unless the party desiring confidentiality protests as provided in this paragraph. The party desiring to restrict the qualified person(s) from accessing specific Confidential Information must provide written notice to the qualified person(s) and counsel for the party associated with the qualified person(s) as soon as the party becomes aware of reasons to restrict access. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis before filing a motion with the Administrative Law Judge. If the dispute cannot be resolved informally, either party may file a motion with the Administrative Law Judge for resolution. Either party may also file a motion if the other party does not respond within five days to a request to resolve the dispute. A motion must describe in detail the intermediate measures, including selected redaction, explored by the parties and explain why such measures do not resolve the dispute. After receipt of the written notice as required in this paragraph, the specific Confidential Information shall not be disclosed to the qualified person(s) until the issue is resolved.

Preservation of Confidentiality-

12. All persons who are given access to any Confidential Information by reason of this order shall not use or disclose the Confidential Information for any purpose other than the purposes of preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

Qualified persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation and conduct of this proceeding. Qualified persons may disclose Confidential Information only to other qualified persons associated with the same party.

Duration of Protection-

13. The Commission shall preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality. The Commission shall notify the party desiring confidentiality at least two weeks prior to the release of confidential information.

Destruction After Proceeding-

14. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Confidential Information to the extent reasonably necessary to maintain a file of this proceeding or to comply with requirements imposed by another governmental agency or court order. The information retained may not be disclosed to any person. Any other person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party desiring confidentiality within 90 days after final resolution of this proceeding unless the party desiring confidentiality consents, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to the Commission or its Staff.

Appeal to the Presiding Officer-

15. If a party disagrees with the designation of information as confidential, the party shall contact the designating party and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute, the party desiring to use the information may move for exclusion of the information from the protection conferred by this order. The motion shall:

a. Specifically identify the contested information, and

b. Assert that the information does not fall within ORCP 36(C)(7) and state the reasons therefore.

The party resisting disclosure has the burden of showing that the challenged information falls within ORCP 36(C)(7). If the party resisting disclosure does not respond to the motion within ten (10) calendar days, the challenged information shall be removed from the protection of this order.

The information shall not be disclosed pending a ruling by the Administrative Law Judge on the motion.

Additional Protection-

16. The party desiring additional protection may move for any of the remedies set forth in ORCP 36(C). The motion shall state:

a. The parties and persons involved;

b. The exact nature of the information involved;

c. The exact nature of the relief requested;

d. The specific reasons the requested relief is necessary; and

e. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

The information need not be released and, if released, shall not be disclosed pending the Commission's ruling on the motion.

ORDER NO.

SIGNATORY PAGE

DOCKET NO. ______________

I. Consent to be Bound-

This Protective Order governs the use of "Confidential Information" in this proceeding.

_________________________PGE agrees to be bound by its terms of this Protective Order.

By: ______________________________ ______________________________

Signature & Printed Date

____

II. Persons Qualified pursuant to Paragraphs 3(a) through 3 (d)

_______________________________PGE identifies the following person(s) automatically qualified under paragraph 3(a) through (d).

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

III. Persons Qualified pursuant to Paragraph 3(e) and Paragraph 10.

I have read the Protective Order, agree to be bound by the terms of the order, and will provide the information identified in paragraph 10.

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

PGE Advice No. 07-08

Excerpts from UE 180 PGE Exhibit 800

II. AMI Proposal

Q. What is AMI?

A. AMI is a system that enables the automated collection of meter data via a fixed network. A complete AMI system consists of solid-state electronic meters; a communication system, or network, to transmit the data; and a communication server or computer system that receives and stores data from the meter, and as a two-way system, sends commands to the meter. This two-way capability enables the utility to send commands to the meter or control devices at the customers' premises.

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

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

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

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

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

A. PGE proposes to implement an AMI system to:

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

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

A. PGE believes now is the appropriate time to launch an AMI project because the technology is mature and a number of parties have signaled their interest in moving forward with future methods of grid management and demand response. We cannot begin to achieve these goals without AMI. While there are longer-term economic benefits to be gained from implementing AMI, the decision to proceed with this project is also a policy decision. For

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

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

III. AMI System

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

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

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

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

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

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

Q. When would the system become operational?

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

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

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

IV. Benefits of AMI

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

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

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

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

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

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[2]*See Demand Response Programs for Oregon Utilities, page 35, prepared by Lisa Schwartz for the OPUC, dated May 2003; see also Powering Up the Smart Grid, at 13* (discussing demand response and automated grid technologies, including automated metering).

.[3]*See Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, page viii, xx, 58-59, U.S. Dept. of Energy (Feb. 2006)* customers when asked in surveys about billing and payment programs they would like to see implemented.

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

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

Q. What economic benefits can result from AMI implementation?

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

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

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

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

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

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

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

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

PGE Advice No. 07-08

Proposed AMI Conditions

Proposed AMI Conditions
February 2007

Operational Implementation Plans

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

- Monthly, beginning in April of 2007 and continuing throughout the deployment process, provide a written status report of progress under the implementation plans, including any significant changes in timing or scope.
- If significant changes are made to the overall AMI project scope that affect implementation plans previously provided, PGE will provide revised implementation plans within 30 days.

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 will:

- By April 15, 2007, appoint 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 don't need separate project management.

- By July 1, 2007, provide OPUC Staff and CUB the Project Charters and schedule at least one meeting within 30 days of submittal to obtain input and feedback on the charters.

- By October 1, 2007, provide OPUC Staff and CUB the 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.

Demand Response

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

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

IRP Capacity Planning

PGE is presently engaged in an Integrated Resource Planning (IRP) process that assesses the availability and cost-effectiveness of firm demand side resources to meet system capacity needs. In the draft that PGE plans to issue in the second quarter of 2007, PGE will:

- Assess conditions (e.g., number of hours, number of customers) under which dispatchable demand side options would be cost effective when compared to supply-side alternatives.

To validate the assumptions and range of effectiveness, PGE will within 90 days after acknowledgement of our IRP (which we plan to file in the second quarter of 2007) either:

- Issue a capacity RFP that will provide for evaluation of both demand side and supply side capacity resources or
- Seek proposals from leading vendors of demand-side resources and evaluate them against supply-side capacity resources.

Should responses to the RFP and/or cost estimates meet IRP requirements and be cost effective, PGE will:

- Enter into discussions with applicable respondents to proceed with a dispatchable capacity peak reduction program with a target start date of July 1, 2009, and
- Submit a tariff to implement a demand side capacity program no more than six months after the RFP closes.

Voluntary Critical Peak Pricing

The IRP will address non-firm critical peak pricing programs, but not necessarily include them as a firm capacity resource. For a non-firm program, PGE will:

- By May 1, 2007, provide to OPUC Staff and CUB a summary document on Critical Peak Pricing. This document has been drafted and is currently going through review by different organizations within PGE. The document addresses market monitoring of other utility efforts, including the California Statewide Pricing Pilot, as well as enabling technologies that may support critical peak pricing.
- Within 30 days of issuance of this document, engage OPUC Staff, CUB and other interested stakeholders in review of program options.
- Within 120 days of completion of the review or by October 1, 2007, whichever is later, prepare an experimental tariff reflecting stakeholder input for Commission consideration.

Appliance Market Transformation

PGE clearly understands that as a mid-sized utility in Oregon, we do not have the political power or resources to drive significant market transformation. However, we do believe we can assist in moving towards that transformation by working with an appliance manufacturer with whom we've already developed a relationship to modify an agreed upon appliance to (1) "hear" 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:

- Within 30 days of the completion of the Project Charter, engage regional stakeholders and appliance manufacturers to identify interest in a technology trial for either water heaters or thermostats.
- Within 30 days of completion of the Project Plan, assemble 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 MW demand response resource through an appliance market-transformation approach or provide a written report to OPUC Staff and CUB detailing barriers to proceeding.

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 will:

- By June 1, 2007, engage OPUC Staff, CUB and other regional stakeholders to share the results of research done to date and plans for additional research to determine customer interest in energy usage information.

- By July 31, 2007, provide OPUC Staff and CUB the Project Charters and schedule at least one meeting within 30 days of submittal to obtain input and feedback on the charters.
- By October 1, 2007, complete a plan using input from the research to develop and launch a test program and associated information tool. This plan will be shared with OPUC Staff, CUB and other regional stakeholders.

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:

- By the dates indicated on page 1 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:

- By the dates indicated on page 1 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:

- By the dates indicated on page 1 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:

- By the dates indicated on page 1 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:

- By the dates indicated on page 1 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 service without having to return later saves outage time and utility costs. PGE will:

- By the dates indicated on page 1 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

About 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.

- By the dates indicated on page 1 for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of these fault detection devices.

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

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

- Quarterly, beginning in April of 2007 and throughout the deployment period, report to the OPUC Staff and CUB on ongoing coordination discussions between PGE and NWN and actions being taken to assure continued coordination during deployment.

PGE Advice No. 07-08

Scoping Plan for AMI Benefits

Draft PGE Scoping Plan for AMI Benefits

I. Introduction

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

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

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

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

Using the current system cost estimate of approximately $130 million, we anticipate $16 million in annual cost savings from operational benefits after the system is fully deployed in 2010. These costs and benefits produce a net present value benefit of approximately $22 million over 20 years of system operation. With the benefits identified in this scoping plan, we estimate that the net present value benefit of deploying AMI now could increase to between $24 million to

$68 million (see Attachment 1) depending on customer acceptance of demand-response initiatives and various other necessary assumptions.

II. Regulatory Status

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

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

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

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

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

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

III. Customer- and System-Related Benefits

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

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

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

Demand Response

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

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

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

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

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

1. For demand response to be successful, the industry needs to gain experience in implementing, promoting, operating, and evaluating these programs.
2. To participate in a meaningful way, most customers will need major appliances that respond automatically and effectively by receiving utility control and/or price signals directly.

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

<u>Demand Response Market Pilot</u>

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

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

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

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

Load Shift
The nominal average value of 0.5 KW shifted per customer is based on PGE's <u>Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option</u> section on CPP. Because this estimate is not based on experience in PGE's service territory, actual results could vary considerably. The Low Scenario assumes 75% of this value and the High Scenario 140%.

Avoided Capacity Cost
The primary benefit driver is the cost of avoided capacity. Again, with almost no industry experience with CPP programs the appropriate value to associate with capacity is difficult to estimate. One alternative is the annual cost associated with a simple cycle combustion turbine (CT). In PGE's IRP, this value is more than $70/kW per year. We believe this avoided cost may

be high, however, for two reasons. First, at least in the recent past, PGE has found capacity resources that cost less than this. Second, there are no restrictions on how many hours a CT provides capacity and a CT provides reactive current support to the transmission grid during peak periods. Gauging from this avoided cost, we used a value of $29 per KW-year in the Low Scenario because this is what we have incurred, to date, to implement resources for PGE's distributed generation program. In the Nominal Scenario we assume a value of $36 per KW-year and $58 in the High Scenario.[1]

<u>Appliance Market Transformation</u>[2]

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

Our plan is to define a technology trial for either water heaters or thermostats whereby a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties[3] develop a project to create a 10 MW demand response resource by decreasing the installed cost per kW through an appliance market-transformation approach. As suggested above, the components of a smart appliance demand response system include (a) a communications-ready appliance, (b) a communications device[4], and (c) a communications method between the customer (or appliance) and the utility (e.g., AMI network).

In the end state of appliance market transformation, the incremental cost to develop a communication-ready appliance is expected to be about $2 to $5 per appliance.[5] When sufficient

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

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

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

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

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

numbers of such appliances exist, the utility can implement a very cost-effective program simply by mailing communication devices to those customers who choose to participate. Also in the end state, we estimate the communication device to cost between $0 and $20 depending on what communication resources already exist in the home. (At the lower volume of the demonstration, a $40 cost is expected.)

The main objectives of the technology trial are to:

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

The milestones in this project are to:

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

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

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

Example Benefit/Cost Analysis[6]

We assume on-peak contribution of water heaters to be 0.85kW. To create a 10 MW resource, PGE customers must purchase approximately 15,000 "smart appliance" water heaters. We also assume 5,000 water heaters are sold in each of three (3) years—3,500 in the replacement market and 1,500 in new construction. An appliance manufacturer will need to contribute non-recurring engineering cost to the project. PGE will pay for incremental hardware cost at the appliance for an estimated $15 per water heater. PGE's marketing cost per water heater is estimated to be $60. In the second or third year, PGE would promote a direct load control and/or a TOU program to the customers owning these water heaters. To achieve an 80% participation rate, PGE might guarantee an annual bill savings to each customer. This amount, however, should have a near

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

zero fulfillment cost, due to energy usage shifted away from on-peak. We estimate the customer-installable communication device to be approximately $40 apiece and other one-time program costs to be approximately $250,000. Consequently, we estimate the total installed capital cost to be approximately $1.6[7] million for a 10 MW resource or approximately $160/kW.

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

Information-Driven Energy Savings

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

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

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

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

Phase 2:

[7] $1,600,000 = 15,000*(($60+$15) 0.8*$40)
[8] Based on an avoid energy cost of $50/MWh. 500,000 = $50/MWh * 4* (500 Customers/wk * 40% * 50 wk/yr * 250 kWh saved annual per customer)/1000. See Attachment 2 for calculation details.

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

The milestones in this project are:

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

Improved Distribution Asset Utilization

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

Avoided Service Transformer Failures

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

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

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

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

<u>Delayed Feeder Conductor Work</u>

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

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

Benefits	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Year 1 Work Deferred	$43,000	$43,000	$43,000	---	---
Year 2 Work Deferred	---	$43,000	$43,000	$43,000	
Year 3 Work Deferred	---	---	$43,000	$43,000	$43,000
Year 4 Work Deferred	---	---	---	$43,000	$43,000
Year 5 Work Deferred	---	---	---	---	$43,000
Engineering Cost	($25,000)	($25,000)	($25,000)	($25,000)	($25,000)
Net Benefit	**$18,000**	**$61,000**	**$104,000**	**$104,000**	**$104,000**

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

Improved Outage Management

Avoided Trouble Calls

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

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

Faster One-Premise Outage Response

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

Annually, approximately 3,000 outages occur that affect only one customer. If we assume that 25% occur when the customer is not at home and that the average incremental cost impact to these customers is at least $15 per outage, the resulting societal benefit would be approximately $12,000 per year, plus or minus 50%. PGE, however, does not yet have an estimate for the cost to integrate AMI with the Outage Management System (OMS). Another consideration is that PGE would have to verify the reliability of the AMI outage data because undetected outages and false positive reports would affect the benefit estimate.

Improved Storm Management

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

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

Assumptions made include the following:

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

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

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

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

<u>Faster Fault Location Identification</u>

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

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

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

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

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

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

dispatchers); thus, the installed cost of 15 such devices on each of 450 feeders would be $1.7 to $2.3 million. This implies an annual cost of about $260,000 (0.13* $2.0 million).

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

<u>Reduced Contact Center Cost</u>

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

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

IV. Timetable

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

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

- Complete research regarding cost and benefits including, where appropriate, examining other utility programs.

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

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

Table 1 Estimated Range of Net Benefits

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

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

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

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

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

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

Attachment 1

Summary NPV

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

Benefit	Low	Normal	High
Demand Response Market Pilot	-	3,095.6	27,404.9
Appliance Market Transformation	-	1,475.8	4,832.3
Info-Driven Energy Savings	1,611.1	4,121.8	9,143.2
Avoided transformer failure	400.0	1,200.0	2,000.0
Deferred Feeder Conductor Work	400.0	1,117.3	1,600.0
Improved Outage Management			
-Avoided Trouble Calls	100.0	200.0	300.0
-Faster One-Premise Response	100.0	150.0	200.0
-Improved Storm Management	18.9	334.3	859.9
-Expedite Fault Location (a)	8,620.2	20,277.2	31,934.2
-Reduced Contact Center Cost	100.0	100.0	100.0
Subtotal NPV - Customer- and System-Related Benefits	**11,350.2**	**32,072.0**	**78,374.5**
Subtotal without Social Benefits of Expedited Fault Location	**2,730.0**	**11,794.8**	**46,440.3**
NPV - AMI Revenue Requirement Analysis (b)	**17,579.6**	**17,579.6**	**17,579.6**
Total NPV	**20,309.7**	**29,374.5**	**64,020.0**

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

Attachment 2

Analysis of Customer- and System-Related Benefits

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

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

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

PGE Advice No. 07-08

Work Papers

Cost Estimate and Revenue Requirement
(Provided on CD only)