Evaluation Plan
for Avista's Natural Gas Decoupling Mechanism

A. Introduction

Avista, with substantial input and comments from the other interested parties in Docket No. UG-060518, has prepared this draft evaluation plan (Plan) for Avista's natural gas decoupling mechanism (Mechanism), as referenced in the Settlement Agreement, included as Appendix A to Order No. 04 (Order) in Docket UG-060518. The parties participating in the development of this Plan are: Avista, the Staff of the Washington Utilities and Transportation Commission, the Public Counsel Section of the Washington State Attorney General's Office, the Northwest Industrial Gas Users, The Energy Project, and The Northwest Energy Coalition. One representative from each party will serve on a Stakeholder Advisory Group (Advisory Group), which will provide oversight and guidance during the course of evaluation of the Mechanism. This Plan shall serve to define the work plan for an independent evaluation of the Mechanism through December 31, 2008.

This Plan is comprised of a number of areas to be examined as part of the Evaluation. These areas are both directly and indirectly related to the Mechanism, and the final Evaluation Report should allow the Commission, Advisory Group members, and interested parties to fully examine the Mechanism.

Whether or not the Company requests an extension of the decoupling mechanism, the Evaluation Report and supporting workpapers will be filed with the Commission by March 31, 2009. The following section of this Plan sets forth the proposed timeline for selection of an independent evaluator and completion of the final Evaluation Report. The succeeding sections generally set forth questions to be answered using the information to be examined and documented by the Evaluator. The Evaluator, once selected, may seek clarification or modification of aspects of the Plan from the Advisory Group, as described in the attached Memorandum of Understanding (MOU), provided as Attachment C to the Request for Proposals.

B. Proposed Timeline for Evaluation

All Parties agree that the Evaluation should be conducted by an independent third-party. The Commission has adopted the following timeline to select an independent evaluator and complete the Evaluation Report (Order 05, UG-060518, ¶ 31).

Proposed Timeline:

April 30, 2008 - Plan filed with the Commission by Avista, including any agreed upon request for proposals (RFP) soliciting an evaluation contractor and any agreed upon Memorandum of Understanding (MOU) among the Parties.

May 9, 2008 - Comments filed with Commission by any Party not endorsing the Plan.

May 10-31, 2008 - Plan and any comments reviewed by Commission for possible guidance to the Parties.

June 16, 2008 – Distribution of the RFP by Avista (based on the work of the Advisory Group).

July 15, 2008 - Proposals due from interested evaluation contractors.

August 6, 2008 - Advisory Group selects top 2-4 candidates to interview.

August 18-22, 2008 - Advisory Group conducts interviews with candidates.

September 5, 2008 - Joint Recommendation or Separate Recommendations filed with Commission concerning Evaluator Selection.

September 26, 2008 - Selection of Evaluator as set forth in Section 14.2 of the Request for Proposals.

January 1, 2009 - Preliminary Evaluation Report with final 2007 results due from Evaluator, submitted to Advisory Committee.

February 28, 2009 - All 2008 data provided to Evaluator, including complete DSM verification for 2008.

March 31, 2009 - Final Evaluation Report filed with Commission.

April 30, 2009 – Avista permitted to petition to extend pilot program.

TBD - Prehearing conference to set schedule for petition docket.

June 30, 2009 - End of Pilot. Deferrals terminate if review process is not complete.

C. Evaluation of Avista DSM Programs and Savings from 2006 – 2008

Information related to Avista's DSM programs and activities will be examined for 2006-2008 as a key part of the Evaluation. As part of the decoupling pilot program, an independent third-party performs an audit of Avista's estimated annual programmatic savings for the annual rate adjustment filing and "DSM test"[1] each year (DSM Verification). The audited DSM savings are based on completed projects during the prior year. Audited programmatic savings for 2006 were used for the DSM-test supporting the decoupling rate adjustment effective November 1, 2007. The independent DSM audit report for 2007 programmatic savings will be completed by August 1, 2008. The

[1] As referenced in Docket No. 060518 – Final Order Approving Decoupling Pilot Program

independent audit report for 2008 programmatic savings will be completed no later than February 28, 2009.

Since the DSM Target for the Pilot Mechanism is based on DSM savings in Washington and Idaho, all data in this section, responding to the questions below, should provide disaggregated results for Washington and Idaho, as well as combined totals.

1) Based on the results of the independent DSM audits, by what amounts did the Company change its DSM program expenditures and its resulting natural gas therm savings through Company-sponsored programs over the term of the Mechanism, relative to the 2004 – 2005 pre-decoupling period? What were the annual audited DSM savings (completed project basis) for 2006-2008, by customer class, by DSM program and by rate schedule, compared to achieved therm savings in the 2004 – 2005 (completed project basis) pre-decoupling period? For any electric or gas DSM programs sponsored by Avista that may produce combined electric and gas savings, or increased gas or electric usage, what assumptions or methods are used to allocate savings to the gas therm values provided in response to this question? What assumptions or methods are used to allocate any kwh savings or increased electric consumption, and what were the amounts of kwh savings or increased electric consumption from any Avista sponsored gas DSM program? The response to this question should make clear that the 2004-2005 completed project DSM data provided by Avista has not been audited.

2) What is the proportion of therm savings from Company-sponsored DSM programs compared to overall weather normalized sales volumes, in total, and by customer class and/or rate schedule for each year 2004, 2005, 2006, 2006, 2007, and 2008?

3) What were the associated lost margins from Company sponsored DSM, by customer class and by rate schedule for each year 2004, 2005, 2006, 2006, 2007, and 2008?

4) During the 2004 – 2008 time period, did the Company change the scope or magnitude of any of its DSM programs in the following areas: a) natural gas DSM programs, b) natural gas or electric DSM programs that may produce combined gas and electric savings, or c) electric DSM programs that may produce changes in gas usage?

5) What incremental program changes or expansions were implemented, and when, during 2004 – 2008, for the three categories of DSM programs described above in question 4? Identify and describe each new, revised or expanded programmatic changes by customer class (residential, commercial, industrial) and corresponding rate schedule.

6) Were there any changes in Avista's avoided costs during the Pilot Period that may have contributed to any changes in customer participation and savings for Company sponsored DSM programs? Identify any other factors that may have contributed to an increase in DSM savings and/or new or expanded DSM program offerings.

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7) What new or revised customer educational, informational and marketing programs related to DSM were implemented by the Company during 2006-2008? What were the primary messages and estimated costs of each of these programs? Were any therm savings attributed to such programs in the independent DSM audit, and if so, how much, and using what assumptions or studies?

8) What were the annual revenues collected from ratepayers under the gas tariff rider (Schedule 191), by rate schedule, to fund gas DSM programs for 2004-2008? What was the gas tariff rider (Schedule 191) surcharge for the years 2004-2008?

9) What were actual yearly DSM expenditures for 2004-2008? How were such amounts spent each year by customer class (residential, limited income, non-residential) and rate schedule? Identify the total expenditures directly distributed to customers (by customer class), and the total expenditures for the administration of the programs.

10) How did Avista's natural gas Integrated Resource Plan (IRP) conservation achievement goal(s) compare to the verified/audited DSM savings each year?

D. Revenue Deferred and Collected under the Mechanism

1) What was the monthly, annual, and cumulative amount of revenue deferred and recovered through the decoupling mechanism during 2007 and 2008, before and after any percentage adjustments to reflect the 90% deferral limitation, as well as any percentage adjustments due to the DSM Test or the Earnings Test?

2) Has Avista made any changes to its methods or calculations of the decoupling deferral over the course of the pilot, as reflected in the quarterly deferral reports? Describe any such changes, their purpose and impact on the deferral.

3) Were there any issues that arose regarding the methodology or input values for calculation of the accounting journal entries which implemented the decoupling deferral? Explain and quantify the impact of any changes in methodology or input values.

4) How do the annual recorded decoupling deferral amounts compare to the Company's estimate of $600,000-$700,000 developed prior to implementation of the Mechanism, as described in Paragraph 24 of the Commission's Order 04?

5) What was the mathematical result of the earnings test and the DSM test for 2006 and 2007, used for and provided in the September 2007 and 2008 rate adjustment filings, respectively?

6) What was the pretax margin and net income impact resulting from the recoverable revenue deferrals for 2007 and 2008 as a result of the pilot? What percentage of total pretax margins and net income for the Company's Washington Gas operations is represented by these deferrals in each year?

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7) What was Avista's Schedule 101 recorded gas margin revenue and recorded gas margin revenue per customer for 2006-2008, before and after decoupling deferrals?

8) What was the total amount of decoupling surcharge revenue collected from ratepayers each month from November 2007 through December 2008?

9) What is the monthly customer bill impact of the decoupling rate adjustment for customers during the three year recovery period?[2] The bill impact analysis should provide actual data for the period November 2007 through October 2008, and anticipated bill impact for the periods November 2008 through October 2009, and November 2009 through October 2010, using the latest available cost of gas and billing determinants. The bill impact analysis shall examine annual usages typical of customers having: a) natural gas space heat, b) water heat, c) both space and water heat, as well as d) the average Schedule 101 levels of annual usage. This should be expressed as an average monthly dollar amount collected and percentage based on the total decoupling amount to be collected divided by total estimated revenue for Schedule 101 customers for the November 2007-October 2008 and estimated for the November 2008-October 2009 and November 2009 through October 2010 periods. Estimate the bill impact of the deferrals from July 2008 through February 2009.

10) What was the total amount of interest accrued under the Mechanism for each month and for the period November 2007-December 2008?

E. Proportion of Margin Lost to Company-Sponsored DSM Relative to the Amount Subject to Recovery

Paragraph 26 of the Commission's Order No. 4 states that the Commission will "closely scrutinize" the proportion of margin lost to Company-sponsored DSM relative to the amount subject to recovery. This information is therefore a key part of the Evaluation.

1) The timing of base rate changes will affect recoveries of lost margins through base rates. The evaluation should therefore identify recoveries of margin through updating of baseline values in rate cases, as well as the deferrals booked under the decoupling authorization.

2) What was the annual amount of estimated lost margin due directly to Company DSM programs/installations for Schedule 101 customers during 2007 and 2008 compared to the annual amount of lost margin calculated (and subject to recovery) under the Mechanism (at both the 100% and 90% levels) ? This analysis should compare the estimated annual reduction in customer usage (therms) and margin ($) directly attributable to Avista's programmatic DSM for Schedule 101 customers to

[2] This bill analysis should make clear that while decoupling deferrals are allowed for 2 years and 6 months, the recovery period is longer (three years).

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the total annual reduction in (weather-corrected) customer usage/margin as calculated under the deferral Mechanism, as well as additional margin revenues provided by Schedule 101 customers as a result of new rates taking effect.

F. Impact of General Rate Cases During Implementation of the Pilot Mechanism

1) Did Avista file any rate cases during the pilot period? If so, when?

2) To the extent new base rates took effect during the pilot period, when did those new rates take effect and what impact did that have on the methods and mechanics of the deferral calculations? Please include changes to base therm sales, weather adjustments, and rate of return.

G. New Customer Usage and Adjustment under the Mechanism

1) What was the impact of the new customer adjustment? For 2007 and 2008, what were the monthly and annual sales volumes deducted for new customer usage, and how do they compare to total sales volumes (both actual and weather normalized sales volumes)?

2) Did Avista's methods to identify, track, and remove new customer usage appear reliable and accurate? Did Avista implement any changes to this methodology during the course of the pilot?

3) If the Mechanism did not include a new customer adjustment, what would have been the impact on the decoupling deferral for 2007 and 2008, at both 100% and 90% levels?

4) What were the monthly numbers of customers served, by rate schedule, in 2006, 2007 and 2008?

5) For 2007 and 2008, what was the actual average annual usage for "new" Schedule 101 customers, as excluded from the monthly deferral calculation compared to the actual average annual usage for existing Schedule 101 customers?

6) Based on the average annual usage for existing Schedule 101 customers determined above, would the inclusion of margins earned from serving new customers in the monthly deferral calculation have increased or decreased annual deferrals and surcharge revenues during 2007 and 2008, and by how much? The average therm use per customer for <u>new</u> customers will be compared with the average use per customer for <u>existing</u> customers in the determination of the impact on the monthly deferral calculations.

7) In this section, please also refer to and discuss the data regarding total sales volumes and total gas margin revenues, provided in response to questions J1 and J2 below.

H. DSM Verification

1) Was the DSM Verification analysis performed, as required by the pilot Mechanism? By whom, and when?

2) What was the cost of the DSM verification analysis, for each year (2006, 2007, 2008)?

3) For each year, what were the verification analysis results? Were Avista's assumed savings levels increased or decreased?

4) Were there any changes in the methodologies used in the independent verification of DSM savings that would have changed the overall audit results during the 2006-2008 time period? What was the resulting impact, if any, on the deferral amount subject to recovery?

5) Based upon the Evaluator's review of the DSM Verification Final Reports, did the Evaluator become aware of any problems or potential inaccuracies within any of the DSM Verification (audit) analyses that were performed, and if so, what is the nature and potential importance of each problem or potential inaccuracy, and would each problem or potential inaccuracy have had any significant impact on the verified results? In that regard, please identify any judgmental assumptions, allocations or methodologies that materially impacted the conclusions that were reached?

I. Customer Migration between Rate Schedules 101 and 111

Schedule 101 (General Service – Firm - Washington) is available for residential and low usage commercial customers that use less than 200 therms per month. Schedule 111 (Large General Service – Firm - Washington) is generally a commercial rate schedule that consists of a higher minimum charge and is based on usage greater than 200 therms per month.

1) What was the monthly number of customer migrations (schedule shifting) between schedules 101 and 111 during the time of the pilot?

2) Based on the answer to #1 above, Did customers migration have any impact upon the decoupling deferrals since initiation of the pilot? Furthermore, what is the actual (or estimated if actual data is not readily available) therm usage resulting from customer migrations between schedules 101 and 111.

3) Does the Company periodically audit or verify Schedule 101 customer eligibility? If so, describe the timing and procedures for such audits.

J . Related Rate and Customer Usage Information (Actual and Forecasted)

1) What were total therm sales (and transportation) volumes by rate schedule, before and after weather normalization in 2006, 2007 and 2008?

2) What were total gas margin revenues by rate schedule, before and after weather normalization in 2006, 2007 and 2008?

3) What was the rate of average annual gas customer growth by rate schedule from 2006-2008? How does this compare to Avista's historical levels of gas customer growth in the 2004-2005 period? What is the Company's forecast for future customer growth? What were the average annual customer count totals by rate schedule for the period 2006-2008?

4) What proportion of Schedule 101 customers were residential versus commercial during the pilot. What proportion of Schedule 101 usage was residential versus commercial during the pilot?

5) On a rate schedule basis, how has both actual and weather normalized annual gas use per customer changed during 2006-2008?

6) What has been the change in the Company's natural gas delivered average monthly price per therm by rate schedule during 2006-2008? Provide a detailed incremental chronological listing (including Docket #) and price per therm impact of all rate adjustments (commodity, general rate case, decoupling, etc.) during the 2006 – 2008 time period. What was the cumulative impact factoring in all rate adjustments from the beginning of 2006 to the end of 2008?

7) What has been the natural gas commodity cost embedded in the average monthly price per therm values by rate schedule in the previous question and how did margin revenues (excluding recovery of gas commodity cost) change during 2006-2008? Provide a detailed incremental chronological listing (including Docket #) and impact of all commodity adjustments during the 2006 – 2008 time period. What was the total impact factoring in all adjustments from the beginning of 2006 to the end of 2008?

8) What is the Company's most recently available five year forecast for (a) natural gas rates/prices, and (b) numbers of customers by rate schedule, and (c) usage per customer by rate schedule, and (d) overall therm volumes and margin revenues by rate schedule in each available projected future period?

K. Impact on Washington Limited Income Customers

1) What is the estimated number of limited income customers in Avista's service territory? In evaluating this question, the evaluator may rely on census data, participation in government programs, and other reliable, public information. Describe the methodology used to develop the estimate.

2) Based on the results of the independent DSM Verification audits, did the Company change its natural gas therm savings through Company-sponsored limited income

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programs for the 2006 – 2008 time period, as compared with 2004 - 2005? What were the annual audited limited income DSM savings (completed project basis) for 2006-2008 for Company sponsored limited income?

3) What is the proportion of therm savings from Company-sponsored limited income DSM programs compared to estimated sales volumes to limited income customers taking service under Schedule 101?

4) What were the associated lost margins from Company sponsored limited income DSM programs?

5) Did Avista make any commitments to program funding, or program changes or expansions as part of any rate cases or other regulatory proceedings during 2004 to 2008? Identify the regulatory proceeding, and provide the program funding, or program changes or expansions Avista made in response.

6) What program funding or program changes or expansions were implemented during the 2006 – 2008 time period for gas, shared savings, or electric efficiency with natural gas impact (either savings or increased usage) on limited income DSM programs as compared with the 2004 – 2005 time period? Identify each new, revised or expanded programmatic change including scope and funding.

7) Were there any changes in Avista's avoided costs during the Pilot Period that may have contributed to any changes in customer participation and savings for Company sponsored limited income DSM programs? Identify any other factors that may have contributed to an increase in limited income DSM savings and/or new or expanded limited income DSM program offerings. ?

8) What limited income DSM customer educational, informational and outreach programs were implemented by the Company during 2006-2008? What were the primary messages, including dates of publication or broadcast, and estimated costs of each of these programs? Were any therm savings attributed to such programs in the independent DSM verification (audit) referenced above in Section (C), and if so, how much, and using what assumptions or studies?

9) What information is captured and retained by Avista to track service provided to limited income customers in the normal course of business, including monitoring of participation in DSM and rate assistance programs?

10) What is Avista's estimate of average usage per customer for customers that have participated in the limited income DSM, LIHEAP and LIRAP programs, in comparison to all Schedule 101 customers, and how was such estimate derived?

11) At the average per customer usage levels for limited income customers provided in response to question #10, what is the approximate cost to a typical limited income customer for funding of DSM programs and for recovery of decoupling deferrals? How does the average cost for recovery of decoupling deferrals compare to the estimated average savings for customers in the limited-income DSM program?

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12) Using the estimate of limited income customers from Question #1, and the estimate of limited income usage in Question #10, what is the estimated proportion of the total amount of decoupling deferrals borne by limited income customers for 2007 and 2008?

13) Identify and summarize any further information or data available that would assist in the determination of whether or not decoupling has a disproportionate impact on limited income customers?

14) What was the total limited income DSM expenditures for 2006, 2007, and 2008? Did Avista make any commitments regarding funding levels as part of any rate cases or other regulatory proceedings? What is Avista's best estimate of the proportion of limited income participation in each of its conservation programs and how such estimates were derived?

15) What was the total distribution of LIRAP funds to limited income customers for 2006, 2007, and 2008? Did Avista make any commitments regarding funding levels as part of any rate cases or other regulatory proceedings? What is Avista's best estimate of the proportion of limited income participation in this program and how was this estimate derived?

16) What was the total distribution of LIHEAP funds to limited income customers for 2006, 2007, and 2008? What is Avista's best estimate of the proportion of limited income participation in this program and how such estimates were derived?

17) Based on a sampling of those customers who receive LIHEAP or LIRAP funds, what was the estimated average surcharge for November 2007 – October 2008 and the estimated impact for November 2008 – October 2009?

18) What is the approximate cost to the limited-income customer population to fund 1) the DSM programs and 2) the recovery of the decoupling deferrals if each of the average usage figures above were applied to the estimated limited income population derived in Section K, Question #1?

L. Other Information

1) Was the decoupling pilot Mechanism in Washington recognized in any public reports issued by credit rating agencies or financial analysts? If so, provide a copy of the report.

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[Service Date February 1, 2007]

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of	)	DOCKET UG-060518
	)	
	)	
AVISTA CORPORATION, D/B/A	)	ORDER 04
AVISTA UTILITIES,	)	
	)	
	)	FINAL ORDER APPROVING
For an Order Authorizing	)	DECOUPLING PILOT PROGRAM
Implementation of a Natural Gas	)	
Decoupling Mechanism and to	)	
Record Accounting Entries	)	
Associated With the Mechanism.	)	
. . . .	)	

1 ***Synopsis:*** *The Commission grants Avista's request for approval of a decoupling mechanism pilot program, and requires an analysis of the pilot program's results. The Order accepts a proposed multiparty settlement, subject to conditions limiting accumulation of interest and carry-over of benefits between periods, and denies requests by other parties to reject the proposal.*

2 **NATURE OF PROCEEDING.** Docket UG-060518 involves a petition by Avista Corporation for authority to implement a mechanism to decouple its rates for conducting business operations, in part, from its rates for commodity sales.

3 **HEARING.** The Washington Utilities and Transportation Commission (Commission) convened a hearing in this docket at Olympia, Washington on December 22, 2006, before Chairman Mark Sidran, Commissioners Patrick Oshie and Philip Jones and Administrative Law Judge C. Robert Wallis.

4 **APPEARANCES.** David Meyer, attorney, Spokane, Washington, represents Avista Corporation (Avista). Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of the Attorney General (Public Counsel). Greg Trautman, Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff). Ron Roseman, attorney, Seattle, represents intervenor The Energy Project. Nancy Glaser, Seattle, represents Intervenor The Northwest Energy Coalition, and Ed

Finklea and Chad Stokes, attorneys, Portland, represent Intervenor Northwest Industrial Gas Users, or NWIGU.

5 **MULTIPARTY SETTLEMENT:** All parties except Public Counsel and The Energy Project have settled their differences and propose a settlement of all issues. Public Counsel and The Energy Project oppose the proposal.

6 **HEARING AND BRIEFING.** The Commission convened an evidentiary hearing in the proceeding on December 22, 2006. The parties submitted prehearing briefs on December 14, 2006, and presented closing arguments at the conclusion of the evidentiary hearing.

7 **DECISION.** The Commission finds that the benefits of this pilot program sufficiently outweigh its potential disadvantages and should be approved. The pilot program, supported by Staff as well as industrial and environmental interests, will allow a test of decoupling from which the parties can obtain objective data and analysis. The proposal is of relatively small scale and includes provisions to ameliorate the minor risk to ratepayers.

BACKGROUND

8 Decoupling is a ratemaking and regulatory tool intended to break the link between a utility's recovery of fixed costs and a consumer's energy consumption by reducing the impact of energy consumption on a utility's recovery of its fixed costs. Conservation advocates view decoupling as an important tool to promote greater conservation efforts by the utility by removing financial discentives.

9 Under traditional ratemaking structures, utilities recover a large portion of their fixed costs through charges based on the volume of energy that consumers use. Consequently, a reduction in energy consumption may lower the probability that the utility can fully recover its fixed costs. Energy consumption may be lower for a variety of reasons. Consumers may lower their thermostats or take shorter showers. More energy efficient building codes and appliances, better and more efficient insulation, and warmer than normal weather can also reduce energy use. Conversely, an increase in energy consumption may lead to a utility over-recovering its fixed costs. The traditional financial incentives rewarding higher sales, some argue, create an environment in which utilities do not support conservation because it is inconsistent with their economic interests.

10 Promoting energy conservation is a goal that we strongly support, and provides a highly appealing rationale for decoupling on its face. Our states' laws and policies encourage us to look with favor upon incentives to stimulate increased energy conservation as well.[1] Our statutory responsibility to regulate in the public interest, however, requires us to look beyond the abstract and examine the specific evidence to determine whether the facts support this rationale for Avista.[2]

11 Some of the parties to this proceeding reached agreement on all disputed issues. The settling parties are the Company, the Commission Staff, NWIGU, and the NWEC, (the Northwest Environmental Coalition), collectively the "Joint Parties."[3] Along with the Northwest Industrial Gas Users (NWIGU) they support adoption of a three-year pilot "partial" decoupling mechanism that they propose as a multiparty settlement.[4]

12 Public Counsel and the Energy Project oppose the proposal.

STANDARDS FOR REVIEWING SETTLEMENT AGREEMENTS

13 The Commission's procedural rules govern the process for reviewing proposed settlement agreements. The Commission "may accept [a] proposed settlement, with or without conditions, or may reject it."[5] The Commission must "determine whether a proposed settlement meets all pertinent legal and policy standards."[6] The Commission may approve settlements "when doing so is lawful, when the settlement

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[1] *See* RCW 80.28.024, RCW 80.28.025, and RCW 80.28.260.
[2] The Commission has determined that it is not desirable to take a blanket approach to decoupling. "The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking." Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005). This is the third in a recent series of decoupling proposals we have considered, including one for Puget Sound Energy, Inc., *WUTC v. Puget Sound Energy, Inc.*, Order 08, Dockets UE-060266 and UG-060267 (2007), and the other for Cascade Natural Gas, *WUTC v. Cascade Natural Gas*, Order 05, Docket UG-060256 (2007). Each proposal has unique qualities and a unique setting which has shaped our analysis and determined our decision.
[3] Though a sponsor of the settlement stipulation, NWIGU did not sign on to the joint testimony, joint rebuttal testimony, or the pre-hearing brief.
[4] WAC 480-07-730.
[5] WAC 480-07-750(2).
[6] WAC 480-07-740.

terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the Commission."[7]

14 In reviewing the proposed settlement, we must consider the terms of the decoupling proposal, and whether those terms are lawful, are supported by the record and are in the public interest.

TERMS OF THE PROPOSED SETTLEMENT

15 The main features of this proposed pilot decoupling mechanism include the following:[8]

- **Term**: It would begin January 1, 2007. Recording of deferred revenue will end on June 30, 2009. However, the amortization period would begin on November 1, 2007 and end on October 31, 2010.

- **Application**: It would apply only to schedule 101 (residential and small commercial customers).

- **New Customer Adjustment**: It would remove the usage associated with new customers added since the corresponding month of the test year.

- **The Deferral Amount**: It would defer 90% of the margin difference, either positive or negative, for later recovery (or rebate).

- **Recovery**: It would subject recovery of deferred costs to:

  - *An earnings test* – Avista could not earn more than its authorized 9.11% rate of return.

  - *A demand side management (DSM) test* – recovery based on Avista achieving specific conservation targets.

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[7] WAC 480-07-750(1).
[8] *See* Exh. 15 (Settlement), ¶¶6A-6J.

Actual vs. Target DSM Savings	Amount Deferred
< 70%	0%
> 70% and < 80%	60%
> 80% and < 90%	70%
> 90% and < 100%	80%
100%	90%

- o Any deferred amount not recovered due to the earnings or DSM tests would carry over and offset future deferrals.[9]
- o Variations due to weather will be excluded from calculations of savings.

- **Review of DSM Savings**: The Company will retain an independent third party to audit the results of DSM savings reported for decoupling purposes.

- **Annual Rate Changes**: The mechanism would limit annual rate increases due to the mechanism to 2% annually.

- **Decoupling Evaluation**: Prior to filing a request to continue the mechanism beyond its initial term, the company must evaluate its results.

16 According to the Joint Parities, the stipulated decoupling mechanism would "break the link between the volume of therm sales and the recovery of fixed costs and would provide for an increased focus on energy efficiency and conservation." They argue that the resulting "increased conservation would not only benefit the individual customers participating in those measures through reduced bills, but would also reduce the overall demand for natural gas, which would help to reduce natural gas prices for all customers."[10] The Joint Parties further assert that the proposed decoupling mechanism "would align the Company's interest with that of its customers with an increased focus on effective DSM programs."[11]

17 Decoupling, like many other departures from traditional ratemaking structures that have come before this Commission, has both potential advantages and disadvantages.

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[9] We address this provision, and require modification, below.
[10] *See* Exh. 10 (Joint Testimony), 7:1-15.
[11] *Id*, 7:22-8:2.

A key disadvantage, as Public Counsel points out, is the potential shifting of risk to ratepayers.[12] Under the stipulated proposal, the risks of changes to weather-normalized consumption would shift to customers. All customers, regardless of their individual efforts to lower use, will experience a surcharge in rates should consumption by class fall below the expected level. This points us to a second potentially serious problem—the distortion of price signals and consequent dampening of customer conservation initiatives.

18 Balancing fixed-cost recovery on an annual basis via a surcharge or credit mechanism diminishes the value of rates as a means to send appropriate price signals to customers. Based on changing energy market conditions, price signals undoubtedly affect customer choices to conserve or not. This price signal may be weakened if customers conserve and then are faced with paying a surcharge that reduces their financial benefit. In those circumstances, decoupling actually may prove counterproductive to its laudable purpose. Just as we must be concerned that in some instances the absence of decoupling or something similar may prove a disincentive to a company promoting conservation, the implementation of decoupling, and associated surcharges, may prove a disincentive to customers who might be inclined to conserve if it is to their financial advantage.

19 A third potential problem, vigorously argued by Public Counsel, is the risk over time of distorting the "matching principle " through single issue ratemaking.[13] Under this principle, revenues and costs are balanced at a common point in time, i.e., a rate case, to determine fair, just, reasonable and sufficient rates. If a company is largely assured recovery of fixed costs and most variable costs are routinely passed through to customers (e.g., via purchased gas adjustment mechanisms and the like), then the company has fewer reasons to file a general rate case. In this context, any cost savings achieved by the company are not shared with customers. The result risks over-earning by the company and over-paying by the customers.

20 Considering these concerns, we must examine carefully the stipulated proposal to determine whether the record is sufficient to prove the potential advantages from decoupling outweigh its potential disadvantages in this case.

21 A fundamental test in this regard is the likelihood of increased conservation as a result of implementing a decoupling program. A key complaint of Public Counsel and the

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[12] Public Counsel Initial Brief, ¶ 91.
[13] *Id.*, ¶¶ 22-28, 56-59.

Energy Project is that there is no guarantee that the decoupling proposal would increase conservation. Public Counsel argues that the stipulation's use of the 2006 Integrated Resource Plan's (IRP) savings level as the conservation target does not satisfy the "requirement for incremental conservation."[14] The Energy Project also expresses skepticism over whether the proposed decoupling mechanism would increase conservation and recommends a higher conservation target.[15]

22 The Joint Parties respond that Avista performed a comprehensive assessment of natural gas efficiency measures to establish its gas savings targets as part of the IRP[16] development process. This effort was carried out with the help of an external oversight group, the External Energy Efficiency Board. As a result, the Joint Parties claim that the savings target is "meaningful and elevated" as well as being "appropriate and in the public interest."[17] The Joint Parties further assert that with the stipulated decoupling program, the Company can continue to encourage customers to conserve natural gas through education, as well as through programmatic DSM.[18] Finally, the Joint Parties claim that the prospect of a decoupling mechanism has already increased the Company's focus on natural gas DSM. The Company has increased resources "to achieve higher DSM goals in 2006 and beyond."[19]

23 We note that the stipulated decoupling mechanism includes a DSM test whereby Avista must achieve *at least* the 2006 IRP's targeted savings level to maximize recovery of deferred costs. Moreover, the Joint Parties point out the 2006 IRP target was based on a comprehensive assessment of available efficiency measures and is about four times the goal of the previous 2004 IRP.[20] Finally, it appears that Avista has recently made efforts to increase its conservation program in anticipation of this decoupling mechanism. Ms. Glaser, testifying on behalf of the Northwest Environmental Council, emphatically supported this view. Together, these factors lead us to conclude that the proposed decoupling mechanism has some potential to increase Company conservation.

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[14] *See* Exh. 51 (Public Counsel Testimony), 12:4-20.
[15] *See* Exh. 60 (Energy Project Testimony), 5.
[16] Integrated Resource Plan, a means by which utilities identify resources to meet likely future loads. *See,* WAC 480-107.
[17] *See* Exh. 11 (Rebuttal Joint Testimony), 3:8-9, 4:17-18.
[18] *Id*, 7:3-11.
[19] *Id*, 7:18-8:7.
[20] *Id*, 3:8-15.

24 Public Counsel also asserts that deferrals under the decoupling mechanism would be far out of proportion to the lost margins from Avista's energy efficiency programs. Of the $617,000 deferral simulated by the Company for the July 2005-June 2006 time period, it alleges that only $141,000 (less than 25 percent) was due to Avista's own conservation efforts.[21] The Joint Parties argue that Public Counsel "fails to recognize that the [decoupling] mechanism is intended to capture up to 90 percent of the lost margin resulting from all reductions in usage… even conservation beyond that which results from the Company's sponsored DSM programs." The Joint Parties further imply that some of the customer conservation results from Company education efforts."[22]

25 Public Counsel makes a strong argument that the decoupling mechanism may recover lost margin far out of proportion to losses from effects of Avista's efficiency programs. As noted above, we are concerned that the mechanism not simply be a way to shift from the Company to customers the risk of falling individual natural gas consumption. That said, it is reasonable to assume, as the Joint Parties do, that company-sponsored educational efforts have an effect on individual efficiency decisions. It is also reasonable to conclude that the application of an earnings cap and the exclusion of weather from the mechanism will prevent such a significant shift in risks that the Company would earn windfall profits—especially over the three-year test period proposed in the stipulation.

26 To ensure that the program does not result in inappropriate benefit to the Company, we require two changes to the proposal. First, any funds that are not deferred due to the "earnings" and/or the "DSM" test may not be carried over to the next period. Second, the Company may not record interest on deferrals until we approve the deferrals for recovery.[23] In light of these changes, we do not find Public Counsel's argument sufficiently strong to prevent implementation of the multi-party settlement. However, the proportion of margin lost to company sponsored DSM relative to the amount subject to recovery is of great interest to us, and we will closely scrutinize this factor in reviewing the results of this pilot decoupling program.

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[21] *See* Public Counsel Pre-Hearing Brief ¶ 5.
[22] *See* Joint Parties Pre-Hearing Brief ¶ 35.
[23] Generally, interest on deferred amounts should be limited to instances where a utility's investors have provided a direct investment. In this instance, the deferral is the amount of money the company would have made if they had earned their authorized rate of return. Since deferral is not derived from investors' finds that are expensed or capitalized, it should also not earn interest.

27 Public Counsel claims that eliminating schedule 111 from the decoupling mechanism creates two serious problems. First, he argues that any incentive resulting from decoupling will benefit Schedule 111 (large user) customers who will not be paying anything to remove the "disincentive." Second, he argues that since the settlement decoupling proposal recovers the full lost margins for all rate schedules, Schedule 101 (residential) customers are paying not only for their own lost margins, but for all Avista's lost sales volumes for all customer schedules. This, he alleges, amounts to a cross-subsidy.[24]

28 The Joint Parties respond that Schedule 111 has a significant number of large commercial and industrial customers, whose gas usage can vary greatly due to economic reasons. These customers should not be part of the pilot decoupling mechanism and it would be difficult to identify, track and remove them from the mechanism. So the Joint Parties agreed to eliminate all of Schedule 111 customers. The Joint Parties further assert that the mechanism determines lost margin only from Schedule 101 customers and any adjustment applies only to those customers. Any lost margin associated with Schedule 111 customers would not be included in the decoupling mechanism.[25]

29 We find little merit in the assertion that decoupling proposal would result in Schedule 101 customers subsidizing Schedule 111 customers. The lost margins would be calculated solely for and apply only to Schedule 101 customers. We also do not agree with the apparent argument that a cross subsidy occurs simply because the conservation tariff rider applies to all customers, but all customers may not equally share in the conservation acquired through the rider. The tariff rider creates a public benefit by providing a pool of funds to acquire the most conservation at the least cost, wherever that may occur. The argument that this creates a cross-subsidy could equally apply to other utility programs such as rate relief provided to some low-income customers.

30 In prior reviews of proposed decoupling mechanisms, we have noted the importance of the information accompanying a general rate case to making a fully informed decision. Although this petition is not part of a general rate case, the fact that Avista

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[24] *Id*, 11:12-22.
[25] *See* Exh. 11 (Rebuttal Joint Testimony), 10:9-15.

had such a case before us within the past *13* months is sufficient in this context to guide our decision.[26]

31 Public Counsel raises substantive concerns as to the appropriateness of decoupling. We conclude that an appropriately designed pilot program with adequate safeguards to protect ratepayers is in the public interest, because it will test the hypothetical benefits of decoupling generally and the specifics of this mechanism set forth in the settlement agreement. This proposal, as conditioned, has many limitations and safeguards to protect the public; it follows a review adequate for the purpose in a rate proceeding decided recently; and it is low-risk, putting ratepayers to a minimal exposure.[27] As modified, this proposal constitutes an acceptable form for a pilot program.

32 To ensure an adequate review of the program and its accomplishments, we require that the program be reviewed at its conclusion in a general rate case.

CONCLUSION

33 The Commission favors the resolution of contested issues through settlement "when doing so is lawful and consistent with the public interest."[28] We have carefully considered the design of the stipulated partial decoupling mechanism, including the public protections afforded by the DSM test and the earnings test on recovery of deferred costs. After reviewing all of the arguments, we determine that it is in the public interest to allow the Company to proceed with this pilot program. However, we agree with Public Counsel and the Energy Project that the proposal is not without potential flaws. The settling parties should consider our approval as an opportunity to demonstrate that decoupling mechanisms do indeed increase utility sponsored conservation and that the potential flaws do not outweigh the program's benefits. We will carefully evaluate the mechanism, and will only consider an extension upon a convincing demonstration that the mechanism has enhanced Avista's conservation efforts in a cost-effective manner.

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[26] We note in contrast our rejection of Avista's petition for a power and transmission cost update outside a general rate case. See, Order 04, docket UE-061411 (2006).
[27] The mechanism limits annual rate increases to a maximum of 2%. Avista's study indicates that if the mechanism had been effective between July 2005 and June 2006, ratepayer exposure would have been 35 cents per month for a typical residential customer. Exh. No. 1, p.11.
[28] WAC 480-07-700.

FINDINGS OF FACT

34 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated above our findings and conclusions upon issues in dispute among the parties and the reasons supporting the findings and conclusions, the Commission now makes and enters the following summary findings of fact, incorporating by reference pertinent portions of the preceding detailed findings:

35 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas companies.

36 (2) Avista Corporation is a "public service company" and a "gas company," as those terms are defined in RCW 80.04.010, and as those terms are used in RCW Title 80. Avista is engaged in Washington State in the business of supplying utility services and natural gas to the public for compensation.

37 (3) Avista filed a petition on April 5, 2006, requesting an order authorizing a natural gas decoupling mechanism which would defer certain costs and revenues in order to potentially recover fixed costs unrelated to consumption.

38 (4) Four parties entered into a multi-party Agreement resolving their differences and agreeing to a pilot program. The settling parties included the Company, Commission Staff, and the Northwest Environmental Coalition (NWEC). In addition, the Northwest Industrial Gas Users (NWIGU) supports the proposed settlement. The Settlement Agreement is attached to this Order as Appendix A.

39 (5) Public Counsel and the Energy Project oppose the settlement proposal.

40 (6) The proposed pilot decoupling program includes sufficient elements, mechanisms and commitments to protect ratepayers and real incentives for the Company to deliver on the promise of conservation. It is likely to increase Company conservation.

41 (7) An evaluation of the pilot, partial decoupling program, regardless of whether Avista seeks to continue the program after the three-year pilot period expires,

is important to determining the value of decoupling mechanisms for regulated utilities in Washington State.

CONCLUSIONS OF LAW

42 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law incorporating by reference pertinent portions of the preceding detailed conclusions:

43 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, this proceeding. *RCW Title 80.*

44 (2) Informal settlements in administrative proceedings are encouraged. *RCW 34.05.060.* The Commission may approve settlements "when doing so is lawful, when the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission." *WAC 480-07-750(1).*

45 (3) The Settlement Agreement is supported by the record, and is consistent with the law and public interest.

46 (4) Avista's petition should be granted, authorizing accounting treatment effective January 1, 2007, as described in the Settlement Agreement to implement a decoupling mechanism pilot program, but only subject to the following conditions: First, any funds that are not deferred due to the "earnings" and/or the "DSM" test may not be carried over to the next period. Second, the Company may not record interest on deferrals until such time as the deferrals are approved for recovery by the Commission. If the parties fail to accept these conditions, this Order shall become void and Avista's petition shall be set for a full hearing on the merits.

47 (5) The Commission should retain jurisdiction over the subject matter of and the parties to this proceeding to effectuate the terms of this Order. *RCW Title 80.*

O R D E R

48 The Commission approves, subject to condition, the Joint Parties' proposal and authorizes Avista to implement accounting treatment, as described in the Settlement agreement, to effect a decoupling mechanism pilot program. For the approval to become effective, the settling parties must each agree within ten business days to a settlement agreement modification containing the following changes: First, any funds that are not deferred due to either the "earnings" and/or the "DMS" test may not be carried over to the next period. Second, the Company may not record interest on deferrals until such time as the deferrals are approved for recovery by the Commission.

49 The multi-party Settlement Agreement filed in this proceeding on October 27, 2006, attached to this Order as Appendix A and incorporated herein by this reference as if set forth in full, is accepted and approved, subject to conditions, as set out in the body of this Order.

Dated at Olympia, Washington, and effective February 1, 2007.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

MARK H. SIDRAN, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

APPENDIX A

PROPOSED SETTLEMENT

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of AVISTA CORPORATON, d/b/a AVISTA UTILITIES, For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism.	))))))))))))	DOCKET NO. UG-060518 SETTLEMENT AGREEMENT

I. PARTIES

1. This Settlement Agreement is entered into by Avista Corporation (the "Company"), the Staff of the Washington Utilities and Transportation Commission ("Staff"), the NW Energy Coalition ("the Coalition"), and Northwest Industrial Gas Users ("NWIGU"), jointly referred to herein as the "Signing Parties." The Public Counsel Section of the Washington Attorney General's Office and The Energy Project do not join in this Settlement. The Signing Parties agree this Settlement Agreement is in the public interest and should be accepted as a resolution of all issues in this docket. The Signing Parties understand this Settlement Agreement is subject to Commission approval.

II. INTRODUCTION

2. The Company filed a Petition, dated April 4, 2006, requesting the Commission to approve a proposed Natural Gas Decoupling Mechanism. The Company also provided a copy of the Petition to representatives of Public Counsel, the Northwest Industrial Gas Users, the Coalition, the Washington Energy Policy Group (Department of Community

Trade and Economic Development or "CTED") and the Spokane Neighborhood Action Program.

Workshops were held on May 17th and June 28th at the Commission's offices to discuss the Company's proposed Mechanism. Representatives of all of the aforementioned organizations were present, as well as a representative of The Energy Project. A number of different issues and alternatives were explored during these workshops. On August 7th, the Company filed an Amendment to its original Petition to address several issues raised by the other parties.

3. A prehearing conference was held on September 6, 2006, and the Coalition, NWIGU and The Energy Project were granted permission to intervene and participate along with Staff and Public Counsel.

4. After analysis of the filing, all parties commenced discussions for purposes of resolving or narrowing the contested issues in this proceeding in a settlement conference held October 16, 2006.

5. The Signing Parties have reached agreement on the issues in this proceeding and wish to present their agreement for the Commission's consideration. This Settlement is the product of discussions among all parties at the aforementioned workshops and settlement conferences. The Signing Parties believe that the Settlement will serve the broader interest of removing disincentives to engage in additional conservation. The Signing Parties therefore adopt the following Settlement Agreement in the interest of expediting the disposition of this proceeding.

III. AGREEMENT

6. The Signing Parties have agreed that the company's Decoupling Mechanism (hereinafter "Mechanism") shall consist of the following:

A. Term of Pilot Program: The implementation of the Mechanism will begin January 1, 2007, whereupon deferred revenue entries would begin being recorded for that month. The proposed term of the Mechanism is 2 years and 6 months for the recording of deferred revenue (January 2007 – June 2009). However, the proposed amortization period would be three years, beginning on November 1, 2007 and ending on October 31, 2010.

B. Application of the Mechanism: The Mechanism would apply only to customers under the Company's natural gas Schedule 101.

C. Calculation of Monthly Deferral Amount: Following the end of each month, the actual volume of weather-corrected therm sales for the calendar month (Current Therm Sales) will be determined and compared with the weather-corrected therm sales for the corresponding month from 2004 (Base Therm Sales), the Company's most recent test year.

(1.) Adjustment for New Customer Usage – Prior to weather-correcting actual therm sales for the month, an adjustment will be made to remove the usage associated with new customers added since the corresponding month of the test year. To the extent the Company has added customers since the test year, these new customers would increase Current Therm Sales as compared to the Base Therm Sales. The actual usage for new customers will be subtracted from the total current month usage.

(2.) Adjustment to Weather-Correct New Usage - Following the subtraction of usage for new customers, the net current month usage will be weather-corrected. The coefficients (usage per degree-day per customer) used to determine the weather adjustment will be the same as those used in the test year, thereby providing a true comparison of the usage between the two periods.

(3.) Comparison of Usage Between Current Month and Test Year – Following the adjustments for new customer usage and weather, the net Current Therm Sales for the month will be compared with the Base Therm Sales to determine the difference in therm sales. This comparison captures the effect of conservation and price elasticity for "existing" customers since the corresponding month of the test year.

(4.) Over/Under-Recovery of Margin Resulting From Usage Differences – The difference in usage will then be multiplied by the approved margin rate for Schedule 101 (sales rate less purchased gas cost per therm) to calculate the fixed distribution costs that are either under-recovered or over-recovered, as compared to the test year.

(5.) Ninety Percent (90%) of Margin Difference Deferred – Ninety percent (90%) of the margin difference, either positive or negative, will be deferred and recorded in a separate account for later recovery (or rebate).

(6.) Effect of Intervening General Rate Case - If the Company files a natural gas general rate filing and the Commission issues its Order in that filing prior to June 30, 2009, the Base Therm Sales and margins resulting from that filing will be used in the Monthly Revenue Deferral Calculation for the remaining months of the pilot term. Any weather adjustment approved in that filing would be used for determining the Base Therm Sales and Current Therm Sales. The authorized rate of return in that filing would be used for the prospective application of the earnings test, as set forth below in Section E.(1.).

D. Rate Adjustments Coincident with Annual PGA: The monthly deferred revenue will be accumulated through June of each year during the term of the Mechanism. If the Mechanism is approved to be effective January 1, 2007, the Company will accumulate the monthly deferred revenue for January through June 2007. It will then file a request to implement a rate adjustment, coincident with the 2007 PGA rate adjustment, to amortize that deferred balance over a twelve-month period, subject to the "earnings" and "DSM" tests described below. For each of the two successive years, the Company will accumulate the deferred revenue for each July-June period, and file a request on or before September 1 to implement the appropriate rate adjustment coincident with the annual PGA. Interest would be accrued on the deferred balance at the same rate applied to the Company's PGA deferral account.

E. Deferred Revenue Recovery Subject to Earnings and DSM Tests: The level of deferred revenue recovery will be subject to (a) an annual earnings test, and (b) a DSM test. The tests will be calculated independently and the test resulting in the lowest surcharge amount would be used.

(1.) Application of Earnings Test - The "earnings-test" will be based on the Company's annual "Commission-basis" operating results, which are filed with the Commission by April 30 for the previous calendar year results. If the Commission-basis rate of return for the Company's Washington gas operations exceeds 9.11%, it would reduce the amount of the proposed surcharge (amount transferred to the balancing account) to bring the rate of return down to 9.11%. (The authorized rate of return of 9.11% is derived from the Commission's Order No. 05 in Docket No. UG-050483.) If removing the entire deferred revenue amount from the Commission-basis results does not reduce the rate of return to 9.11%, no surcharge would be implemented. Where the amount of the surcharge is reduced as a result of the earnings test, the amount of deferred revenue remaining (not recovered through the surcharge) will be carried forward and used to offset future deferrals that would otherwise be recorded, rather than written off the Company's books. (See Attachment 1 for illustration of Earnings Test)

(2.) Application of DSM Test – The "DSM test" relates to the Company achieving pre-established natural gas DSM target savings during the prior year. The Company's 2006 Integrated Resource Plan (IRP) sets forth a natural gas (Washington & Idaho) target savings level of 1,062,000 therms for each of the calendar years 2006 and 2007.[1] This target savings level for each year will be used for determining the level of the 2007 and 2008 surcharges; the target savings level included in the Company's 2008 IRP will be used for the 2009 surcharge. The Company will file its 2008 gas DSM goal as a tariff revision to its decoupling tariff, which will provide an opportunity for review and comment from all interested parties. The following table shows the level of the surcharge (as a percentage of the margin difference between the current year and the test year) based on the actual gas DSM savings compared to the pre-established IRP target:

[1] The expected cost to achieve this savings target is $2.5 million for 2006 and $3 million for 2007.

Actual vs Target DSM Savings	Surcharge vs Margin Difference
< 70%	0%
≥ 70% and <80%	60%
≥ 80% and < 90%	70%
≥ 90% and < 100%	80%
≥ 100%	90% (amount deferred)

If less than 70% of the target savings are achieved, the surcharge amount will be zero. DSM savings achieved between 70% and 100% of the target will result in the corresponding surcharge level shown in the above table. Any deferred revenue that cannot be recovered through a surcharge as a result of not meeting at least 100% of the DSM target will be carried forward and used to offset future deferrals that would otherwise be recorded. (See Attachment 2 for illustration of DSM Test)

F. Independent Third Party Review of DSM Savings: The Company will retain an independent third party to audit the results of DSM savings reported for decoupling purposes. This independent auditor will be chosen through an "RFP" process reviewed and approved by the parties to this Settlement Agreement. The scope of the audit will include an appropriate sampling of projects to verify the work completed, the savings recorded, and a review of the engineering estimates used to estimate the savings.

The cost of the audit will be funded through DSM tariff rider funds and will not exceed $35,000 per year. (The Company will change the present method of recognizing DSM savings for decoupling reporting purposes to one where all savings associated with a project are recognized at the time the entire project is completed in order to reduce the cost of the audit, and for purposes of applying the DSM test in Section E.(2) above.)

G. Annual Two Percent (2%) Rate Change Limitation: After applying the "earnings" and "DSM" tests, the amount of the rate increase resulting from the adjustment will be subject to an annual incremental limit of 2%, i.e., the annual increase in the surcharge cannot exceed a 2% rate increase each year (cumulative of 6% over the initial term). The incremental surcharge (percentage) increase will be determined by subtracting the annual revenue amount recovered by the present surcharge rate from deferred revenue to be recovered through the proposed surcharge rate, and dividing that net amount by the total "normalized" revenue for Schedule 101 for the most recent July – June period. The normalized revenue would be determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental surcharge would exceed a 2% rate increase, only a 2% increase would be implemented and any excess deferred revenue will remain in the deferred revenue account and could be recovered the following year, subject to the 2% limitation.

H. Annual Decoupling Rate Adjustment Filing: On or before September 1, 2007, the Company will file a proposed decoupling surcharge (or rebate) based on the amount of deferred revenue recorded for the prior January through June 2007 period. For the September 2008 and 2009 filings, the proposed rate adjustment would reflect the total deferred revenue for an entire year (July-June). The results of the "earnings", "DSM" and "2%" tests will be included with the filing and used to determine the amount of the rate adjustment. A proposed tariff will be included in those filings. A sample tariff for the decoupling rate adjustment is attached for illustrative purposes as Attachment 3. The Company presently files its Commission-Basis Earnings report (for the prior year) by April 30th and will file its DSM report in advance of the decoupling filing.

The proposed tariff will reflect a rate adjustment that would recover the deferred revenue amount over a twelve-month period to be implemented coincident with the Company's annual PGA. If the rate adjustment is approved by the Commission, the deferred revenue amount approved for recovery or rebate will be transferred to a balancing account and the revenue surcharged or rebated during the period will reduce the deferred revenue in the balancing account. Any deferred revenue remaining in the balancing account at the end of the year, resulting from over- or under-collection, will be added to the new revenue deferrals to determine the amount of the proposed surcharge for the following year.

I. Accounting and Quarterly Reporting for the Mechanism: The Company will record the deferred revenue in account 186 – Miscellaneous Deferred Debits. The amount approved for recovery will be transferred into a 182.3 - Regulatory Asset account for amortization of the surcharge revenue received. On the income statement, the Company would record both the deferred revenue and the amortization of the deferred revenue through Account 407 - Regulatory Debits and Credits, in separate sub-accounts. The Company will file a quarterly report with the Commission showing pertinent information regarding the Mechanism. This information will include a spreadsheet showing the monthly revenue deferral calculation for each month of the current deferral period (July – most recent month), as well as the current and historical monthly balance in the deferral account.

J. Evaluation Plan and Extension of Mechanism: On or before March 31, 2009 (three months prior to the end of the pilot deferral term), the Company may file a request to continue the Mechanism beyond its initial term. That filing would include an evaluation of the Mechanism and any proposed modifications of the Company. Any party is free to argue that the renewal of the Mechanism is only appropriate in the context of a general rate case. The Company would bear the burden of demonstrating why the pilot program should be extended other than in the context of a general rate case.

The Company, Commission Staff, and other interested parties will develop, through a collaborative process, a draft evaluation plan to be filed with the Commission no later than December 31, 2007.

IV. EFFECT OF THE SETTLEMENT AGREEMENT AND PROCEDURE

7. Binding on Parties. The Signing Parties agree to support the terms of the Settlement Agreement throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Settlement Agreement contained herein. The Signing Parties understand that this Settlement Agreement is subject to Commission approval. The Signing Parties agree that this Settlement Agreement represents a compromise in the positions of the Signing Parties. As such, conduct, statements and documents disclosed in the negotiation of this Settlement Agreement shall not be admissible evidence in this or any other proceeding.

8. Integrated Terms of Settlement. The Signing Parties have negotiated this Settlement Agreement as an integrated document. Accordingly, the Signing Parties recommend that the Commission adopt this Settlement Agreement in its entirety. Each

Signing Party has participated in the drafting of this Settlement Agreement, so it should not be construed in favor of, or against, any particular Party.

9. Procedure. The Signing Parties shall cooperate in submitting this Settlement Agreement promptly to the Commission for acceptance. The Signing Parties shall make available a witness or representative in support of this Settlement Agreement. The Signing Parties agree to cooperate, in good faith, in the development of such other information as may be necessary to support and explain the basis of this Settlement Agreement and to supplement the record accordingly.

The Signing Parties agree to stipulate into evidence the prefiled direct testimony and exhibits of the Company, together with such evidence in support of the Agreement as may be offered at the time of the hearing on the Settlement. If the Commission rejects all or any material portion of this Settlement Agreement, or adds additional material conditions, each Signing Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the date of the Commission's Order, to withdraw from the Settlement Agreement. If any Signing Party exercises its right of withdrawal, this Settlement Agreement shall be void and of no effect, and the Signing Parties will support a joint motion for an expedited procedural schedule to address the issues that would otherwise have been settled herein.

10. No Precedent. The Signing Parties enter into this Settlement Agreement to avoid further expense, uncertainty, and delay. By executing this Settlement Agreement, no Signing Party shall be deemed to have accepted or consented to the facts, principles, methods or theories employed in arriving at the Settlement Agreement, and except to the extent expressly set forth in the Settlement Agreement no Signing Party shall be deemed

to have agreed that such a Settlement Agreement is appropriate for resolving any issues in any other proceeding.

11 Public Interest. The Signing Parties agree that this Settlement Agreement is in the public interest and results in rates which are fair, just, reasonable and sufficient.

12. Execution. This Settlement Agreement may be executed by the Signing Parties in several counterparts and as executed shall constitute one agreement.

Entered into this 27th day of October, 2006

Company: By:

David J. Meyer
VP, Chief Counsel for Regulatory and Governmental Affairs

Staff: By: ______________________

Gregory J. Trautman
Assistant Attorney General
Counsel for Commission Staff

The NW Energy Coalition By: ______________________
Nancy Glaser
The NW Energy Coalition

Northwest Industrial Gas Users By: ______________________
Edward A. Finklea
Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Entered into this 27th day of October, 2006

Company:	By:________________ David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs
Staff:	By: ________________ Gregory J. Trautman Assistant Attorney General Counsel for Commission Staff
The NW Energy Coalition	By: ________________ Nancy Glaser The NW Energy Coalition
Northwest Industrial Gas Users	By: ________________ Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Entered into this 27th day of October, 2006

Company:	By: David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs
Staff:	By: Gregory J. Trautman Assistant Attorney General Counsel for Commission Staff
The NW Energy Coalition	By: Nancy Glaser Nancy Glaser The NW Energy Coalition
Northwest Industrial Gas Users	By: ______________________ Edward A. Finklea Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Entered into this 27th day of October, 2006

Company: By:________________________

David J. Meyer
VP, Chief Counsel for Regulatory and Governmental Affairs

Staff: By: ________________________

Gregory J. Trautman
Assistant Attorney General
Counsel for Commission Staff

The NW Energy Coalition By: ________________________
Nancy Glaser
The NW Energy Coalition

Northwest Industrial Gas Users By: Edward A. Finklea
Edward A. Finklea
Cable, Huston, Benedict, Haagenson & Lloyd, LLP

Triple-E Report
January 1, 2004 – December 31, 2004

Avista's DSM Team
Jon Powell
Renee Coelho
Chris Drake
Catherine Bryan
Tom Kliewer
Rob Gray
Eric Lee
Tom Lienhard
Mike Littrel
Bruce Folsom
Lori Hermanson

Table 1E **Electric Utility Costs Aggregated by Programs and Customer Segments**

	Incentives[1]	Implementation	TOTAL
SEGMENTS			
Commercial/Industrial	$ 2,031,223	$ 580,967	$ 2,612,190
Limited Income	$ 704,581	$ 72,436	$ 777,017
Residential	$ 148,038	$ 25	$ 148,063
GENERAL			
General (Implementation)	$ 25	$ 308,614	$ 308,639
OTHER EXPENDITURES			
Regional[2]	$ -	$ 732,219	$ 732,219
TOTAL	**$ 2,883,867**	**$ 1,694,261**	**$ 4,578,128**
BROKEN OUT BY CATEGORY			
Total assigned to segments	$ 2,883,842	$ 653,428	$ 3,537,270
Total assigned to general	$ 25	$ 308,614	$ 308,639
Total assigned to other	$ -	$ 732,219	$ 732,219
TOTAL	**$ 2,883,867**	**$ 1,694,261**	**$ 4,578,128**
CATEGORY AS A PERCENT			
Total assigned to segment	63.0%	14.3%	77.3%
Total assigned to general	0.0%	6.7%	6.7%
Total assigned to other pgms.	0.0%	16.0%	16.0%
TOTAL	**63.0%**	**37.0%**	**100.0%**
Total non-regional utility cost	**$ 2,883,867**	**$ 962,042**	**$ 3,845,909**

NOTES:

1) Incentives are accounted for on a cash basis and will not match de-rated incentive expenditures amounts.
2) Costs associated with membership in NEEA are included in this table, but are excluded from all other tables.

Table 1G **Gas Utility Costs Aggregated by Programs and Customer Segments**

	Incentives[1]	Implementation	TOTAL
SEGMENTS			
Commercial/Industrial	$ 487,422	$ 91,102	$ 578,524
Limited Income	$ 260,582	$ -	$ 260,582
Residential	$ 193,143	$ 119	$ 193,262
GENERAL			
General	$ -	$ 49,297	$ 49,297
OTHER EXPENDITURES			
Regional[2]	$ -	$ -	$ -
TOTAL	**$ 941,147**	**$ 140,517**	**$ 1,081,665**
BROKEN OUT BY CATEGORY			
Total assigned to segments	$ 941,147	$ 91,220	$ 1,032,368
Total assigned to general	$ -	$ 49,297	$ 49,297
Total assigned to other	$ -	$ -	$ -
TOTAL	**$ 941,147**	**$ 140,517**	**$ 1,081,665**
CATEGORY AS A PERCENT			
Total assigned to segment	87.0%	8.4%	95.4%
Total assigned to general	0.0%	4.6%	4.6%
Total assigned to other pgms.	0.0%	0.0%	0.0%
TOTAL	**87.0%**	**13.0%**	**100.0%**
Total non-regional utility cost	**$ 941,147**	**$ 140,517**	**$ 1,081,665**

NOTES:

1) Incentives are accounted for on a cash basis and will not match de-rated incentive expenditures amounts.
2) Costs associated with gas programs in support of regional initiatives appear in this table but are excluded from other tables.

Table 1EG **Electric Utility Costs Aggregated by Programs and Customer Segments**

	Incentives[1]	Implementation	TOTAL
SEGMENTS			
Commercial/Industrial	$ 2,518,645	$ 672,069	$ 3,190,714
Limited Income	$ 965,164	$ 72,436	$ 1,037,600
Residential	$ 341,180	$ 144	$ 341,324
GENERAL			
General (Implementation)	$ 25	$ 357,910	$ 357,935
OTHER EXPENDITURES			
Regional[2]	$ -	$ 732,219	$ 732,219
TOTAL	**$ 3,825,015**	**$ 1,834,778**	**$ 5,659,793**
BROKEN OUT BY CATEGORY			
Total assigned to segments	$ 3,824,990	$ 744,648	$ 4,569,638
Total assigned to general	$ 25	$ 357,910	$ 357,935
Total assigned to other	$ -	$ 732,219	$ 732,219
TOTAL	**$ 3,825,015**	**$ 1,834,778**	**$ 5,659,793**
CATEGORY AS A PERCENT			
Total assigned to segment	67.6%	13.2%	80.7%
Total assigned to general	0.0%	6.3%	6.3%
Total assigned to other pgms.	0.0%	12.9%	12.9%
TOTAL	**67.6%**	**32.4%**	**100.0%**
Total non-regional utility cost	**$ 3,825,015**	**$ 1,102,559**	**$ 4,927,573**

NOTES:

1) Incentives are accounted for on a cash basis and will not match de-rated incentive expenditures amounts.

2) Costs associated with gas programs in support of regional initiatives appear in this table but are excluded from other tables.

Table 2E — **Assignment of Non-Regional Electric Utility Costs to Customer Segments**

	Directly charged incentive cost [A]	Directly charged implementation cost [B]	Assigned general cost [E]	Total directly charged costs [F]	Total assigned general cost [H]	Total utility cost [I]
Commercial/Industrial	$ 2,031,223	$ 580,967	$ 242,677	$ 2,612,190	$ 242,677	$ 2,854,868
Limited Income	$ 704,606	$ 72,436	$ 21,923	$ 777,042	$ 21,923	$ 798,965
Residential	$ 148,038	$ 25	$ 44,014	$ 148,063	$ 44,014	$ 192,076
	$ 2,883,867	$ 653,428	$ 308,614	$ 3,537,295	$ 308,614	$ 3,845,909

Table 2G — **Assignment of Non-Regional Gas Utility Costs to Customer Segments**

	Directly charged incentive cost [A]	Directly charged implementation cost [B]	Assigned general cost [E]	Total directly charged costs [F]	Total assigned general cost [H]	Total utility cost [I]
Commercial/Industrial	$ 487,422	$ 91,102	$ 42,787	$ 578,524	$ 42,787	$ 621,311
Limited Income	$ 260,582	$ -	$ 791	$ 260,582	$ 791	$ 261,374
Residential	$ 193,143	$ 119	$ 5,719	$ 193,262	$ 5,719	$ 198,980
	$ 941,147	$ 91,220	$ 49,297	$ 1,032,368	$ 49,297	$ 1,081,665

NOTES:

Column [A] Represents direct cash incentives. This does not reconcile to accrued incentives used for cost-effectiveness calculations.
Column [B] Represents implementation costs that were charged directly to each customer segment.
Column [C] The cash incentive cost associated with temporary programs that was assigned to each customer segment based on 2002 operations.
Column [D] The implementation cost associated with temporary programs that was assigned to each customer segment based on 2002 operations.
Column [E] General costs have been assigned to customer segments based upon that segments share of energy acquired during 2002.
Column [F] The sum of directly assigned implementation and cash incentive costs.
Column [G] The sum of directly assigned implementation and cash incentive costs associated with temporary programs.
Column [H] Equal to Column [E].
Column [I] The total utility cost, including incentives but excluding costs associated with regional programs, for each customer segment.

Table 3E — **Allocation of Incentive and Non-Incentive (Non-Regional) Electric Utility Costs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL $	% of Portfolio
Commercial/Industrial	$ 82,282	$ -	$ 280,813	$ 784	$ 1,057,077	$ 445,450	$ 596,224	$ -	$ 258,198	$ -	$ -	$ 84,634	$ 49,404	$ -	$ 2,854,868	74.2%
Limited Income	$ 471,514	$ -	$ -	$ -	$ 246,769	$ -	$ 5,774	$ -	$ -	$ -	$ -	$ -	$ 74,908	$ -	$ 798,965	20.8%
Residential	$ 31,016	$ -	$ -	$ -	$ 144,785	$ -	$ -	$ -	$ -	$ -	$ 95	$ -	$ 16,181	$ -	$ 192,076	5.0%
TOTAL $	$ 584,813	$ -	$ 280,813	$ 784	$ 1,448,631	$ 445,450	$ 601,998	$ -	$ 258,198	$ -	$ 95	$ 84,634	$ 140,493	$ -	$ 3,845,909	100.0%
% of portfolio	15.2%	0.0%	7.3%	0.0%	37.7%	11.6%	15.7%	0.0%	6.7%	0.0%	0.0%	2.2%	3.7%	0.0%	100.0%	

NOTES:
Incentives are de-rated for degree of project completion to match recognition of kWh and therm claims.
Costs associated with regional programs are excluded from this table, and are excluded from all cost-effectiveness calculations.

Table 3G — **Allocation of Incentive and Non-Incentive (Non-Regional) Gas Utility Costs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL $	% of Portfolio
Commercial/Industrial	$ 1,811	$ -	$ -	$ 1	$ 407,790	$ 4,372	$ 1,231	$ -	$ -	$ -	$ -	$ 122,944	$ 83,163	$ -	$ 621,311	57.4%
Limited Income	$ 9,077	$ -	$ -	$ -	$ 38,199	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 214,097	$ -	$ 261,374	24.2%
Residential	$ 9,407	$ -	$ -	$ -	$ 98,541	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 91,032	$ -	$ 198,980	18.4%
TOTAL $	$ 20,295	$ -	$ -	$ 1	$ 544,530	$ 4,372	$ 1,231	$ -	$ -	$ -	$ -	$ 122,944	$ 388,292	$ -	$ 1,081,665	100.0%
% of portfolio	1.9%	0.0%	0.0%	0.0%	50.3%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	11.4%	35.9%	0.0%	100.0%	

NOTES:
Incentives are de-rated for degree of project completion to match recognition of kWh and therm claims.
Costs associated with regional programs are excluded from this table, and are excluded from all cost-effectiveness calculations.

Table 4E

Allocation of Electric Direct Incentives Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL $	% of Portfolio
Commercial/Industrial	$ 58,544	$ -	$ 199,797	$ 558	$ 752,105	$ 316,936	$ 424,210	$ -	$ 183,707	$ -	$ -	$ 60,217	$ 35,151	$ -	$ 2,031,223	70.4%
Limited Income	$ 415,828	$ -	$ -	$ -	$ 217,625	$ -	$ 5,092	$ -	$ -	$ -	$ -	$ -	$ 66,061	$ -	$ 704,606	24.4%
Residential	$ 23,905	$ -	$ -	$ -	$ 111,589	$ -	$ -	$ -	$ -	$ -	$ 73	$ -	$ 12,471	$ -	$ 148,038	5.1%
TOTAL $	$ 498,276	$ -	$ 199,797	$ 558	$ 1,081,319	$ 316,936	$ 429,303	$ -	$ 183,707	$ -	$ 73	$ 60,217	$ 113,683	$ -	$ 2,883,867	100.0%
% of portfolio	17.3%	0.0%	6.9%	0.0%	37.5%	11.0%	14.9%	0.0%	6.4%	0.0%	0.0%	2.1%	3.9%	0.0%	100.0%	

NOTES:

Incentives represented in this table are calculated on a cash basis

Table 4G

Allocation of Gas Direct Incentives Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	TOTAL $	% of Portfolio
Commercial/Industrial	$ 1,421	$ -	$ -	$ 0	$ 319,913	$ 3,430	$ 965	$ -	$ -	$ -	$ -	$ 96,450	$ 65,242	$ -	$ 487,422	51.8%
Limited Income	$ 9,050	$ -	$ -	$ -	$ 38,084	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 213,449	$ -	$ 260,582	27.7%
Residential	$ 9,131	$ -	$ -	$ -	$ 95,650	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 88,362	$ -	$ 193,143	20.5%
TOTAL $	$ 19,601	$ -	$ -	$ 0	$ 453,647	$ 3,430	$ 965	$ -	$ -	$ -	$ -	$ 96,450	$ 367,053	$ -	$ 941,147	100.0%
% of portfolio	2.1%	0.0%	0.0%	0.0%	48.2%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	10.2%	39.0%	0.0%	100.0%	

NOTES:

Incentives represented in this table are calculated on a cash basis

Table 5E — **Allocation of Electric Savings Attributable to Electric Programs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	787,189	-	2,686,511	7,500	10,112,974	4,261,588	5,704,031	-	2,470,162	-	-	809,689	472,647	-	27,312,292	78.6%
Limited Income	1,456,107	-	-	-	762,060	-	17,831	-	-	-	-	-	231,328	-	2,467,326	7.1%
Residential	799,888	-	-	-	3,733,918	-	-	-	-	-	2,440	-	417,291	-	4,953,537	14.3%
TOTAL kWh	3,043,184	-	2,686,511	7,500	14,608,953	4,261,588	5,721,862	-	2,470,162	-	2,440	809,689	1,121,266	-	34,733,154	100.0%
% of portfolio	8.8%	0.0%	7.7%	0.0%	42.1%	12.3%	16.5%	0.0%	7.1%	0.0%	0.0%	2.3%	3.2%	0.0%	100.0%	

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NOTES:

These savings include derated kWh savings from the contracted and construction phases.

Energy savings claims made in this table are electric kWh savings attributable to electric programs (arising from joint or interactive savings effects).

Table 5G — **Allocation of Electric Savings Attributable to Gas Programs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	-	-	-	-	(569)	-	-	-	-	-	-	-	(2,566)	-	(3,135)	100.0%
Limited Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Residential	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
TOTAL kWh	-	-	-	-	(569)	-	-	-	-	-	-	-	(2,566)	-	(3,135)	100.0%
% of portfolio	0.0%	0.0%	0.0%	0.0%	18.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	81.8%	0.0%	100.0%	

NOTES:

These savings include derated kWh savings from the contracted and construction phases.

Energy savings claims made in this table are electric kWh savings attributable to gas programs.

Table 6E — **Allocation of Gas Savings Attributable to Electric Programs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	(1,751)	-	-	-	(78,424)	-	(25,608)	-	-	-	-	-	-	-	(105,783)	85.1%
Limited Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%
Residential	-	-	-	-	(18,468)	-	-	-	-	-	-	-	-	-	(18,468)	14.9%
TOTAL therms	(1,751)	-	-	-	(96,892)	-	(25,608)	-	-	-	-	-	-	-	(124,251)	100.0%
% of portfolio	1.4%	0.0%	0.0%	0.0%	78.0%	0.0%	20.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	

NOTES:

These savings include derated therm savings from the contracted and construction phases.

Energy savings claims made in this table are gas therms savings attributable to electric programs (arising from joint or interactive savings effects).

Table 6G — **Allocation of Gas Savings Attributable to Gas Programs Across Customer Segments and Technologies**

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	2,723	-	-	1	613,177	6,574	1,851	-	-	-	-	184,866	125,048	-	934,239	86.8%
Limited Income	600	-	-	-	2,525	-	-	-	-	-	-	-	14,152	-	17,277	1.6%
Residential	5,903	-	-	-	61,837	-	-	-	-	-	-	-	57,125	-	124,865	11.6%
TOTAL therms	9,226	-	-	1	677,539	6,574	1,851	-	-	-	-	184,866	196,325	-	1,076,381	100.0%
% of portfolio	0.9%	0.0%	0.0%	0.0%	62.9%	0.6%	0.2%	0.0%	0.0%	0.0%	0.0%	17.2%	18.2%	0.0%	100.0%	

NOTES:

These savings include derated therm savings from the contracted and construction phases.

Energy savings claims made in this table are gas therm savings attributable to gas programs.

Table 7E

Allocation of Electric Non-Energy Benefits Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	$ 2,805	$ -	$ 16,102	$ 312	$ 651,452	$ 6,296,795	$ 723,621	$ -	$ 9,112	$ -	$ -	$ -	$ 971	$ -	$ 7,701,169	99.9%
Limited Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Residential	$ -	$ -	$ -	$ -	$ 9,255	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,255	0.1%
TOTAL	$ 2,805	$ -	$ 16,102	$ 312	$ 660,707	$ 6,296,795	$ 723,621	$ -	$ 9,112	$ -	$ -	$ -	$ 971	$ -	$ 7,710,424	100.0%
% of portfolio	0.0%	0.0%	0.2%	0.0%	8.6%	81.7%	9.4%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	

NOTES:

This table does not include non-energy benefits which were not sufficiently quantifiable to be claimed as part of the project benefits.

Table 7G

Allocation of Gas Non-Energy Benefits Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	$ -	$ -	$ -	$ -	$ 45,533	$ (2,794)	$ 7,346	$ -	$ -	$ -	$ -	$ -	$ 7,099	$ -	$ 57,185	100.0%
Limited Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
TOTAL	$ -	$ -	$ -	$ -	$ 45,533	$ (2,794)	$ 7,346	$ -	$ -	$ -	$ -	$ -	$ 7,099	$ -	$ 57,185	100.0%
% of portfolio	0.0%	0.0%	0.0%	0.0%	79.6%	-4.9%	12.8%	0.0%	0.0%	0.0%	0.0%	0.0%	12.4%	0.0%	100.0%	

NOTES:

This table does not include non-energy benefits which were not sufficiently quantifiable to be claimed as part of the project benefits.

Table 8E

Allocation of Electric Customer Costs Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	$ 345,477	$ -	$ 632,557	$ 800	$ 2,320,853	$ 4,044,527	$ 2,003,342	$ -	$ 892,393	$ -	$ -	$ 45,616	$ 136,913	$ -	$ 10,422,478	79.5%
Limited Income	$ 306,374	$ -	$ -	$ -	$ 137,276	$ -	$ 10,116	$ -	$ -	$ -	$ -	$ -	$ 113,953	$ -	$ 567,719	4.3%
Residential	$ 581,302	$ -	$ -	$ -	$ 1,484,442	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,324	$ -	$ 2,128,068	16.2%
TOTAL	$ 1,233,153	$ -	$ 632,557	$ 800	$ 3,942,571	$ 4,044,527	$ 2,013,459	$ -	$ 892,393	$ -	$ -	$ 45,616	$ 313,190	$ -	$ 13,118,265	100.0%
% of portfolio	9.4%	0.0%	4.8%	0.0%	30.1%	30.8%	15.3%	0.0%	6.8%	0.0%	0.0%	0.3%	2.4%	0.0%	100.0%	

Table 8G

Allocation of Gas Customer Costs Across Customer Segments and Technologies

	Appliances	Assistive Technologies	Compressed Air	Controls	HVAC	Industrial Process	Lighting	Monitoring	Motors	New Tech	Renewables	Resource Management	Shell	Sustainable Building	Total	% of Portfolio
Commercial/Industrial	$ 27,672	$ -	$ -	$ -	$ 2,937,739	$ 6,254	$ 10,121	$ -	$ -	$ -	$ -	$ 24,384	$ 1,337,371	$ -	$ 4,343,540	79.2%
Limited Income	$ 26,949	$ -	$ -	$ -	$ 106,405	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,661	$ -	$ 197,016	3.6%
Residential	$ 39,600	$ -	$ -	$ -	$ 655,134	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 251,380	$ -	$ 946,114	17.2%
TOTAL	$ 94,222	$ -	$ -	$ -	$ 3,699,278	$ 6,254	$ 10,121	$ -	$ -	$ -	$ -	$ 24,384	$ 1,652,412	$ -	$ 5,486,670	100.0%
% of portfolio	1.7%	0.0%	0.0%	0.0%	67.4%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.4%	30.1%	0.0%	100.0%	

Table 9E Electric Cost-Effectiveness Statistics by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Commercial/Industrial	1.55	4.53	2.04	0.74
Limited Income	1.39	1.39	NA	0.45
Residential	0.90	7.11	1.40	0.66
PORTFOLIO	1.44	4.12	2.04	0.70

NOTES:

Cost-effectiveness calculations do not include costs or benefits associated with regional programs.
"N/A" is listed for segments with benefits, but no costs.

Table 9G Gas Cost-Effectiveness Statistics by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Commercial/Industrial	0.88	3.58	0.02	3.58
Limited Income	0.42	0.42	NA	0.24
Residential	0.62	3.01	1.40	0.47
PORTFOLIO	0.82	3.07	0.31	1.68

NOTES:

Cost-effectiveness calculations do not include costs or benefits associated with regional programs.
"N/A" is listed for segments with benefits, but no costs.

Table 10E Electric Cost-Effectiveness Statistics by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliances	0.65	1.73	1.63	0.47
Assistive Technology	NA	NA	NA	NA
Compressed Air	1.14	3.12	1.78	0.75
Controls	1.89	2.13	24.31	0.52
HVAC	1.57	5.28	2.33	0.76
Industrial Process	1.93	4.64	2.14	0.79
Lighting	0.96	4.04	1.49	0.62
Monitoring	NA	NA	NA	NA
Motors	1.06	4.77	1.56	0.74
New Technology	NA	NA	NA	NA
Renewables	14.73	3.79	-7.32	0.59
Resource Management	1.30	3.93	6.52	0.28
Shell	1.49	2.95	3.83	0.62
Sustainable Building	NA	NA	NA	NA
PORTFOLIO	1.44	4.12	2.04	0.70

NOTES:

Cost-effectiveness calculations do not include costs or benefits associated with regional programs.
"N/A" is listed for segments with benefits, but no costs.

Table 10G Gas Cost-Effectiveness Statistics by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliances	0.27	0.53	0.91	0.28
Assistive Technology	NA	NA	NA	NA
Compressed Air	NA	NA	NA	NA
Controls	22.54	22.54	NA	22.54
HVAC	0.88	3.40	0.21	2.16
Industrial Process	3.17	9.43	-0.63	9.43
Lighting	1.23	22.26	0.73	22.26
Monitoring	NA	NA	NA	NA
Motors	NA	NA	NA	NA
New Technology	NA	NA	NA	NA
Renewables	NA	NA	NA	NA
Resource Management	4.82	9.69	0.00	9.69
Shell	0.57	2.21	0.50	0.91
Sustainable Building	NA	NA	NA	NA
PORTFOLIO	0.82	3.07	0.31	1.68

NOTES:

Cost-effectiveness calculations do not include costs or benefits associated with regional programs.
"N/A" is listed for segments with benefits, but no costs.

Table 11E — Electric Net Benefits by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Commercial/Industrial	$ 6,132,647	$ 7,677,387	$ 9,356,757	$ (3,554,596)
Limited Income	$ 247,120	$ 247,120	$ 1,305,184	$ (1,058,064)
Residential	$ (220,526)	$ 1,749,295	$ 800,265	$ (1,089,901)
PORTFOLIO	$ 6,159,241	$ 9,673,802	$ 11,462,206	$ (5,702,561)

NOTES:

Costs and benefits included in each cost-effectiveness test are detailed in Table 13.

Costs associated with regional programs are excluded from all cost-effectiveness calculations.

Table 11G — Gas Net Benefits by Customer Segment

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Commercial/Industrial	$ (550,796)	$ 2,779,725	$ (3,330,521)	$ 2,781,152
Limited Income	$ (116,485)	$ (116,485)	$ 150,601	$ (267,087)
Residential	$ (367,162)	$ 397,264	$ 306,783	$ (673,945)
PORTFOLIO	$ (1,034,443)	$ 3,060,503	$ (2,873,136)	$ 1,840,120

NOTES:

Costs and benefits included in each cost-effectiveness test are detailed in Table 13.

Costs associated with regional programs are excluded from all cost-effectiveness calculations.

Table 12E — Electric Net Benefits by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliances	$ (458,883)	$ 361,430	$ 515,556	$ (979,652)
Assistive Technology	$ -	$ -	$ -	$ -
Compressed Air	$ 95,789	$ 534,393	$ 353,766	$ (257,977)
Controls	$ 895	$ 1,009	$ 2,664	$ (1,769)
HVAC	$ 2,494,014	$ 5,009,747	$ 4,239,326	$ (2,060,293)
Industrial Process	$ 3,872,411	$ 1,363,304	$ 4,322,843	$ (450,433)
Lighting	$ (89,026)	$ 1,203,739	$ 872,800	$ (1,041,229)
Monitoring	$ -	$ -	$ -	$ -
Motors	$ 55,810	$ 796,199	$ 417,936	$ (362,126)
New Technology	$ -	$ -	$ -	$ -
Renewables	$ 928	$ 732	$ 1,624	$ (697)
Resource Management	$ 20,075	$ 65,691	$ 251,652	$ (231,578)
Shell	$ 167,229	$ 337,557	$ 484,039	$ (316,809)
Sustainable Building	$ -	$ -	$ -	$ -
PORTFOLIO	$ 6,159,241	$ 9,673,802	$ 11,462,206	$ (5,702,561)

NOTES:

Costs and benefits included in each cost-effectiveness test are detailed in Table 13.

Regional program costs and benefits are excluded from all cost-effectiveness calculations.

Table 12G — Gas Net Benefits by Technology

	Total Resource Cost Test	Utility Cost Test	Participant Test	Non-Participant Test
Appliances	$ (69,501)	$ (23,442)	$ (4,014)	$ (65,487)
Assistive Technology	$ -	$ -	$ -	$ -
Compressed Air	$ -	$ -	$ -	$ -
Controls	$ 2	$ 2	$ -	$ 2
HVAC	$ (449,951)	$ 2,325,049	$ (2,215,788)	$ 1,766,096
Industrial Process	$ 15,465	$ 22,681	$ (7,216)	$ 22,681
Lighting	$ 2,362	$ 5,137	$ (2,775)	$ 5,137
Monitoring	$ -	$ -	$ -	$ -
Motors	$ -	$ -	$ -	$ -
New Technology	$ -	$ -	$ -	$ -
Renewables	$ -	$ -	$ -	$ -
Resource Management	$ 185,245	$ 209,629	$ (24,384)	$ 209,629
Shell	$ (718,066)	$ 521,447	$ (618,960)	$ (97,938)
Sustainable Building	$ -	$ -	$ -	$ -
PORTFOLIO	$ (1,034,443)	$ 3,060,503	$ (2,873,136)	$ 1,840,120

NOTES:

Costs and benefits included in each cost-effectiveness test are detailed in Table 13.

Regional program costs and benefits are excluded from all cost-effectiveness calculations.

Table 13E **Summary of Electric Cost-Effectiveness Tests and Descriptive Statistics**

Total Resource Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ 12,437,087	$ 883,179	$ 13,320,266
Non-Energy benefits	$ 7,469,074	$ -	$ 7,469,074
Natural Gas avoided cost	$ (549,792)	$ -	$ (549,792)
TRC benefits	$ 19,356,369	$ 883,179	$ 20,239,548
Non-incentive utility cost	$ 893,702	$ 68,340	$ 962,042
Customer cost	$ 12,550,546	$ 567,719	$ 13,118,265
TRC costs	$ 13,444,248	$ 636,059	$ 14,080,307
TRC ratio	**1.44**	**1.39**	**1.44**
Net TRC benefits	**$ 5,912,121**	**$ 247,120**	**$ 6,159,241**

Utility Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ 12,437,087	$ 883,179	$ 13,320,266
Natural Gas avoided cost	$ (549,792)	$ -	$ (549,792)
UCT benefits	$ 11,887,295	$ 883,179	$ 12,770,474
Non-incentive utility cost	$ 893,702	$ 68,340	$ 962,042
Incentive cost	$ 1,566,911	$ 567,719	$ 2,134,630
UCT costs	$ 2,460,613	$ 636,059	$ 3,096,672
UCT ratio	**4.83**	**1.39**	**4.12**
Net UCT benefits	**$ 9,426,682**	**$ 247,120**	**$ 9,673,802**

Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric Bill Reduction	$ 14,620,971	$ 1,305,184	$ 15,926,155
Gas Bill Reduction	$ (949,388)	$ -	$ (949,388)
Non-Energy benefits	$ 7,469,074	$ -	$ 7,469,074
Participant benefits	$ 21,140,657	$ 1,305,184	$ 22,445,841
Customer project cost	$ 12,550,546	$ 567,719	$ 13,118,265
Incentive received	$ (1,566,911)	$ (567,719)	$ (2,134,630)
Participant costs	$ 10,983,635	$ -	$ 10,983,635
Participant Test ratio	**1.92**	**NA**	**2.04**
Net Participant benefits	**$ 10,157,022**	**$ 1,305,184**	**$ 11,462,206**

Electric Non-Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost savings	$ 12,437,087	$ 883,179	$ 13,320,266
Non-Participant benefits	$ 12,437,087	$ 883,179	$ 13,320,266
Electric Revenue loss	$ 14,620,971	$ 1,305,184	$ 15,926,155
Non-incentive utility cost	$ 893,702	$ 68,340	$ 962,042
Customer incentives	$ 1,566,911	$ 567,719	$ 2,134,630
Non-Participant costs	$ 17,081,584	$ 1,941,243	$ 19,022,827
Non-Part. ratio	**0.73**	**0.45**	**0.70**
Net Non-Part. benefits	**$ (4,644,497)**	**$ (1,058,064)**	**$ (5,702,561)**

Descriptive Statistics	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Annual kWh savings	32,265,828	2,467,326	34,733,154
Annual therm savings	(124,251)	-	(124,251)
Levelized TRC cost per kWh	$ 0.0484	$ 0.0313	$ 0.0472
Levelized UCT cost per kWh	$ 0.0089	$ 0.0313	$ 0.0104

NOTES:

Costs associated with membership in regional programs are excluded from all cost-effectiveness calculations.

"N/A" is listed for segments with benefits, but no costs.

Table 13G **Summary of Gas Cost-Effectiveness Tests and Descriptive Statistics**

Total Resource Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ (1,427)	$ -	$ (1,427)
Non-Energy benefits	$ 57,185	$ -	$ 57,185
Natural Gas avoided cost	$ 4,454,201	$ 82,786	$ 4,536,987
TRC benefits	$ 4,509,958	$ 82,786	$ 4,592,744
Non-incentive utility cost	$ 138,262	$ 2,255	$ 140,517
Customer cost	$ 5,289,654	$ 197,016	$ 5,486,670
TRC costs	$ 5,427,916	$ 199,271	$ 5,627,187
TRC ratio	**0.83**	**0.42**	**0.82**
Net TRC benefits	**$ (917,958)**	**$ (116,485)**	**$ (1,034,443)**

Utility Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ (1,427)	$ -	$ (1,427)
Natural Gas avoided cost	$ 4,454,201	$ 82,786	$ 4,536,987
UCT benefits	$ 4,452,773	$ 82,786	$ 4,535,559
Non-incentive utility cost	$ 138,262	$ 2,255	$ 140,517
Incentive cost	$ 1,137,523	$ 197,016	$ 1,334,539
UCT costs	$ 1,275,785	$ 199,271	$ 1,475,056
UCT ratio	**3.49**	**0.42**	**3.07**
Net UCT benefits	**$ 3,176,988**	**$ (116,485)**	**$ 3,060,503**

Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric Bill Reduction	$ -	$ -	$ -
Gas Bill Reduction	$ 1,071,209	$ 150,601	$ 1,221,811
Non-Energy benefits	$ 57,185	$ -	$ 57,185
Participant benefits	$ 1,128,394	$ 150,601	$ 1,278,995
Customer project cost	$ 5,289,654	$ 197,016	$ 5,486,670
Incentive received	$ (1,137,523)	$ (197,016)	$ (1,334,539)
Participant costs	$ 4,152,131	$ -	$ 4,152,131
Participant Test ratio	**0.27**	**NA**	**0.31**
Net Participant benefits	**$ (3,023,737)**	**$ 150,601**	**$ (2,873,136)**

Gas Non-Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Gas avoided cost savings	$ 4,454,201	$ 82,786	$ 4,536,987
Non-Part benefits	$ 4,454,201	$ 82,786	$ 4,536,987
Gas Revenue loss	$ 1,071,209	$ 150,601	$ 1,221,811
Non-incentive utility cost	$ 138,262	$ 2,255	$ 140,517
Customer incentives	$ 1,137,523	$ 197,016	$ 1,334,539
Non-Part costs	$ 2,346,994	$ 349,872	$ 2,696,867
Non-Part. ratio	**1.90**	**0.24**	**1.68**
Net Non-Part. benefits	**$ 2,107,207**	**$ (267,087)**	**$ 1,840,120**

Descriptive Statistics	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Annual kWh savings	(3,135)	-	(3,135)
Annual therm savings	1,059,104	17,277	1,076,381
Levelized TRC cost per therm	$ 0.578	$ 1.301	$ 0.590
Levelized UCT cost per therm	$ 0.136	$ 1.301	$ 0.155

NOTES:

Costs associated with membership in regional programs are excluded from all cost-effectiveness calculations.

"N/A" is listed for segments with benefits, but no costs.

Table 13EG **Summary of Combined Gas and Electric Cost-Effectiveness Tests and Descriptive Statistics**

Total Resource Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ 12,435,660	$ 883,179	$ 13,318,839
Non-Energy benefits	$ 7,526,258	$ -	$ 7,526,258
Natural Gas avoided cost	$ 3,904,409	$ 82,786	$ 3,987,195
TRC benefits	$ 23,866,327	$ 965,965	$ 24,832,292
Non-incentive utility cost	$ 1,031,963	$ 70,596	$ 1,102,559
Customer cost	$ 17,840,200	$ 764,735	$ 18,604,935
TRC costs	$ 18,872,164	$ 835,330	$ 19,707,494
TRC ratio	**1.26**	**1.16**	**1.26**
Net TRC benefits	**$ 4,994,163**	**$ 130,635**	**$ 5,124,798**

Utility Cost Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric avoided cost	$ 12,435,660	$ 883,179	$ 13,318,839
Natural Gas avoided cost	$ 3,904,409	$ 82,786	$ 3,987,195
UCT benefits	$ 16,340,069	$ 965,965	$ 17,306,033
Non-incentive utility cost	$ 1,031,963	$ 70,596	$ 1,102,559
Incentive cost	$ 2,704,435	$ 764,735	$ 3,469,169
UCT costs	$ 3,736,398	$ 835,330	$ 4,571,728
UCT ratio	**4.37**	**1.16**	**3.79**
Net UCT benefits	**$ 12,603,671**	**$ 130,635**	**$ 12,734,305**

Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Electric Bill Reduction	$ 14,620,971	$ 1,305,184	$ 15,926,155
Gas Bill Reduction	$ 121,821	$ 150,601	$ 272,423
Non-Energy benefits	$ 7,526,258	$ -	$ 7,526,258
Participant benefits	$ 22,269,051	$ 1,455,786	$ 23,724,836
Customer project cost	$ 17,840,200	$ 764,735	$ 18,604,935
Incentive received	$ (2,704,435)	$ (764,735)	$ (3,469,169)
Participant costs	$ 15,135,766	$ -	$ 15,135,766
Participant Test ratio	**1.47**	**NA**	**1.57**
Net Participant benefits	**$ 7,133,285**	**$ 1,455,786**	**$ 8,589,071**

Gas and Electric Non-Participant Test	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Gas avoided cost savings	$ 4,454,201	$ 82,786	$ 4,536,987
Electric avoided cost savings	$ 12,437,087	$ 883,179	$ 13,320,266
Non-Part benefits	$ 16,891,288	$ 965,965	$ 17,857,253
Gas Revenue loss	$ 1,071,209	$ 150,601	$ 1,221,811
Electric Revenue loss	$ 14,620,971	$ 1,305,184	$ 15,926,155
Non-incentive utility cost	$ 1,031,963	$ 70,596	$ 1,102,559
Customer incentives	$ 2,704,435	$ 764,735	$ 3,469,169
Non-Part costs	$ 19,428,578	$ 2,291,116	$ 21,719,694
Non-Part. ratio	**0.87**	**0.42**	**0.82**
Net Non-Part. benefits	**$ (2,537,290)**	**$ (1,325,151)**	**$ (3,862,441)**

Descriptive Statistics	Regular Income portfolio	Limited Income portfolio	Overall portfolio
Annual kWh savings	32,262,693	2,467,326	34,730,019
Annual therm savings	934,853	17,277	952,130

NOTES:

Costs associated with membership in regional programs are excluded from all cost-effectiveness calculations.
"N/A" is listed for segments with benefits, but no costs.

Table 14EG — **Tariff Rider Balances**

	January	February	March	April	May	June	July	August	September	October	November	December	1-1-04 to 12-31-04
WASHINGTON ELECTRIC TARIFF RIDER													
Actual WA Rev[1]	$ 858,531	$ 406,104	$ 378,162	$ 345,379	$ 322,467	$ 320,756	$ 339,060	$ 398,210	$ 356,753	$ 793,966	$ 351,325	$ 110,883	$ 4,981,596
Actual WA Exp	$ 191,786	$ 91,274	$ 182,986	$ 600,481	$ 174,067	$ 92,598	$ 250,746	$ 202,775	$ 175,734	$ 155,829	$ 94,868	$ 228,260	$ 2,441,406
Adjustments[2]	$ -	$ -	$ 25,800	$ -	$ -	$ -	$ (1,697)	$ (283,055)	$ -	$ (200,350)	$ -	$ (292,743)	$ (752,045)
Balance reduction	$ 666,745	$ 314,830	$ 220,976	$ (255,102)	$ 148,400	$ 228,158	$ 86,615	$ (87,620)	$ 181,019	$ 437,787	$ 256,457	$ (410,120)	$ 1,788,145
Starting balance	$ (4,472,526)	$ (3,805,781)	$ (3,490,951)	$ (3,269,975)	$ (3,525,077)	$ (3,376,677)	$ (3,148,519)	$ (3,061,904)	$ (3,149,524)	$ (2,968,505)	$ (2,530,718)	$ (2,274,261)	
Ending balance	$ (3,805,781)	$ (3,490,951)	$ (3,269,975)	$ (3,525,077)	$ (3,376,677)	$ (3,148,519)	$ (3,061,904)	$ (3,149,524)	$ (2,968,505)	$ (2,530,718)	$ (2,274,261)	$ (2,684,381)	
IDAHO ELECTRIC TARIFF RIDER													
Actual ID Rev	$ 308,749	$ 278,202	$ 257,513	$ 244,264	$ 232,750	$ 226,875	$ 250,296	$ 260,442	$ 251,652	$ 235,507	$ 245,672	$ 40,905	$ 2,832,827
Actual ID Exp	$ 41,649	$ 46,781	$ 63,262	$ 205,033	$ 42,025	$ 142,159	$ 511,828	$ 373,117	$ 320,735	$ 95,990	$ 123,944	$ 158,117	$ 2,124,640
Adjustments[2]	$ -	$ -	$ (25,800)	$ -	$ -	$ -	$ 1,697	$ 283,055	$ -	$ 200,350	$ -	$ 292,743	$ 752,045
	$ 267,100	$ 231,421	$ 168,451	$ 39,231	$ 190,725	$ 84,716	$ (259,835)	$ 170,380	$ (69,083)	$ 339,867	$ 121,728	$ 175,531	$ 1,460,232
Starting balance	$ 140,813	$ 407,913	$ 639,334	$ 807,785	$ 847,016	$ 1,037,741	$ 1,122,457	$ 862,622	$ 1,033,002	$ 963,919	$ 1,303,786	$ 1,425,514	
Ending balance	$ 407,913	$ 639,334	$ 807,785	$ 847,016	$ 1,037,741	$ 1,122,457	$ 862,622	$ 1,033,002	$ 963,919	$ 1,303,786	$ 1,425,514	$ 1,601,045	
COMBINED ELECTRIC TARIFF RIDERS													
Actual Rev	$ 1,167,280	$ 684,306	$ 635,675	$ 589,643	$ 555,217	$ 547,631	$ 589,356	$ 658,652	$ 608,405	$ 1,029,473	$ 596,997	$ 151,788	$ 7,814,423
Actual Exp	$ 233,435	$ 138,055	$ 246,248	$ 805,514	$ 216,092	$ 234,757	$ 762,576	$ 575,892	$ 496,469	$ 251,819	$ 218,812	$ 386,377	$ 4,566,046
Adjustments[2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Balance reduction	$ 933,845	$ 546,251	$ 389,427	$ (215,871)	$ 339,125	$ 312,874	$ (173,220)	$ 82,760	$ 111,936	$ 777,654	$ 378,185	$ (234,589)	$ 3,248,377
Starting balance	$ (4,331,713)	$ (3,397,868)	$ (2,851,617)	$ (2,462,190)	$ (2,678,061)	$ (2,338,936)	$ (2,026,062)	$ (2,199,282)	$ (2,116,522)	$ (2,004,586)	$ (1,226,932)	$ (848,747)	
Ending balance	$ (3,397,868)	$ (2,851,617)	$ (2,462,190)	$ (2,678,061)	$ (2,338,936)	$ (2,026,062)	$ (2,199,282)	$ (2,116,522)	$ (2,004,586)	$ (1,226,932)	$ (848,747)	$ (1,083,336)	
WASHINGTON GAS TARIFF RIDER													
Actual WA Rev[3]	$ 324,246	$ 263,604	$ 215,242	$ 132,331	$ 89,723	$ 66,668	$ 44,834	$ 39,293	$ 45,646	$ 66,090	$ 149,354	$ 533,696	$ 1,970,727
Actual WA Exp	$ 54,269	$ 45,436	$ 26,485	$ 69,126	$ 144,358	$ 61,492	$ 39,559	$ 79,488	$ 47,111	$ 38,356	$ 51,975	$ 50,560	$ 708,215
Adjustments[2]	$ -	$ -	$ 87,238	$ -	$ -	$ -	$ (43,619)	$ (3,648)	$ -	$ (26,193)	$ -	$ 16,509	$ 30,287
Balance reduction	$ 269,977	$ 218,168	$ 275,995	$ 63,205	$ (54,635)	$ 5,176	$ (38,344)	$ (43,843)	$ (1,465)	$ 1,541	$ 97,379	$ 499,645	$ 1,292,799
Starting balance	$ (1,092,428)	$ (822,451)	$ (604,283)	$ (328,288)	$ (265,083)	$ (319,718)	$ (314,542)	$ (352,886)	$ (396,729)	$ (398,194)	$ (396,653)	$ (299,274)	
Ending balance	$ (822,451)	$ (604,283)	$ (328,288)	$ (265,083)	$ (319,718)	$ (314,542)	$ (352,886)	$ (396,729)	$ (398,194)	$ (396,653)	$ (299,274)	$ 200,371	
IDAHO GAS TARIFF RIDER													
Actual ID Rev	$ 50,860	$ 41,671	$ 33,444	$ 22,325	$ 15,210	$ 12,059	$ 8,425	$ 7,454	$ 8,254	$ 12,764	$ 23,653	$ 39,444	$ 275,563
Actual ID Exp	$ 13,207	$ 30,176	$ 28,075	$ 72,307	$ 10,388	$ 80,740	$ 11,742	$ 7,072	$ 17,529	$ 54,184	$ 41,124	$ 18,987	$ 385,531
Adjustments[2]	$ -	$ -	$ (87,238)	$ -	$ -	$ -	$ 43,619	$ 3,648	$ -	$ 26,193	$ -	$ (16,509)	$ (30,287)
	$ 37,653	$ 11,495	$ (81,869)	$ (49,982)	$ 4,822	$ (68,681)	$ 40,302	$ 4,030	$ (9,275)	$ (15,227)	$ (17,471)	$ 3,948	$ (140,255)
Starting balance	$ (543,338)	$ (505,685)	$ (494,190)	$ (576,059)	$ (626,041)	$ (621,219)	$ (689,900)	$ (649,598)	$ (645,568)	$ (654,843)	$ (670,070)	$ (687,541)	
Ending balance	$ (505,685)	$ (494,190)	$ (576,059)	$ (626,041)	$ (621,219)	$ (689,900)	$ (649,598)	$ (645,568)	$ (654,843)	$ (670,070)	$ (687,541)	$ (683,593)	
COMBINED GAS TARIFF RIDERS													
Actual Rev	$ 375,106	$ 305,275	$ 248,686	$ 154,656	$ 104,933	$ 78,727	$ 53,259	$ 46,747	$ 53,900	$ 78,854	$ 173,007	$ 573,140	$ 2,246,290
Actual Exp	$ 67,476	$ 75,612	$ 54,560	$ 141,433	$ 154,746	$ 142,232	$ 51,301	$ 86,560	$ 64,640	$ 92,540	$ 93,099	$ 69,547	$ 1,093,746
Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Adjustments[2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Balance reduction	$ 307,630	$ 229,663	$ 194,126	$ 13,223	$ (49,813)	$ (63,505)	$ 1,958	$ (39,813)	$ (10,740)	$ (13,686)	$ 79,908	$ 503,593	$ 1,152,544
Starting balance	$ (1,635,766)	$ (1,328,136)	$ (1,098,473)	$ (904,347)	$ (891,124)	$ (940,937)	$ (1,004,442)	$ (1,002,484)	$ (1,042,297)	$ (1,053,037)	$ (1,066,723)	$ (986,815)	
Ending balance	$ (1,328,136)	$ (1,098,473)	$ (904,347)	$ (891,124)	$ (940,937)	$ (1,004,442)	$ (1,002,484)	$ (1,042,297)	$ (1,053,037)	$ (1,066,723)	$ (986,815)	$ (483,222)	
COMBINED GAS AND ELECTRIC TARIFF RIDERS													
Actual Rev	$ 1,542,386	$ 989,581	$ 884,361	$ 744,299	$ 660,150	$ 626,358	$ 642,615	$ 705,399	$ 662,305	$ 1,108,327	$ 770,004	$ 724,928	$ 10,060,713
Actual Exp	$ 300,911	$ 213,667	$ 300,808	$ 946,947	$ 370,838	$ 376,989	$ 813,877	$ 662,452	$ 561,109	$ 344,359	$ 311,911	$ 455,924	$ 5,659,792
Balance reduction	$ 1,241,475	$ 775,914	$ 583,553	$ (202,648)	$ 289,312	$ 249,369	$ (171,262)	$ 42,947	$ 101,196	$ 763,968	$ 458,093	$ 269,004	$ 4,400,921
Starting balance	$ (5,967,479)	$ (4,726,004)	$ (3,950,090)	$ (3,366,537)	$ (3,569,185)	$ (3,279,873)	$ (3,030,504)	$ (3,201,766)	$ (3,158,819)	$ (3,057,623)	$ (2,293,655)	$ (1,835,562)	
Ending balance	$ (4,726,004)	$ (3,950,090)	$ (3,366,537)	$ (3,569,185)	$ (3,279,873)	$ (3,030,504)	$ (3,201,766)	$ (3,158,819)	$ (3,057,623)	$ (2,293,655)	$ (1,835,562)	$ (1,566,558)	

NOTES:

1) January revenues were $458,531 plus $400,000 tax refund applied to the reduction of negative tariff rider balance. December revenues were $410,883 less $300,000 tax refund reversal.
2) The March, July, August, October and December adjustments represent a jurisdictional transfer resulting from periodic true-ups between projected and actual jurisdictional expense allocations.
3) December revenues were $233,696 plus transfer from Washington Electric of tax refund.

Table 15EG Calculation of Energy Savings vs. Utility Expenditure Proportionality

	Adjusted Proportionality Calculation				Unadjusted Proportionality Calculation			
		Electric		Gas		Electric		Gas
Actual 1/1/04 to 12/31/04 cash expenditures	$	4,578,128	$	1,081,665	$	4,578,128	$	1,081,665
Less cash incentives	$	(2,883,867)	$	(941,147)	$	-	$	-
Add in derated incentives	$	2,134,630	$	1,334,539	$	-	$	-
Adjusted (for incentives) utility expenditures	$	3,828,892	$	1,475,056	$	4,578,128	$	1,081,665
Normalize NEEA expenditures	$	67,781	$	-	$	-	$	-
Total adjusted utility expenditures	$	3,896,672	$	1,475,056	$	4,578,128	$	1,081,665
DSM revenues 1/1/04 to 12/31/04	$	7,814,423	$	2,246,290	$	7,814,423	$	2,246,290
Adjusted utility expenditures divided by actual revenues		50%		66%		59%		48%
Energy savings from Triple-E Report		34,733,154		1,076,381		34,733,154		1,076,381
Tariff goal		40,000,000		240,000		40,000,000		240,000
% of goal achieved		87%		448%		87%		448%
Proportionality (kWh and therm)		**174%**		**683%**		**148%**		**931%**
Proportionality (mmbtu)		**270%**				**247%**		

NOTES:

(1) Adjustments for the difference between cash incentives and those accrued as projects move through the "pipeline" (contracted to construction to completed) remove the effect of scheduling cash payment of incentives to future dates.

(2) NEEA revenues have been adjusted to equal our annual maximum contractual obligation. Regional energy savings are not reflected in this calculation.