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Witness:	Michael L. Stahlman
Sponsoring Party:	MO PSC Staff
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Case No.:	GT-2011-0410
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MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

REBUTTAL TESTIMONY

OF

MICHAEL L. STAHLMAN

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. GT-2011-0410

Jefferson City, Missouri
September 2011

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Union Electric Company's (d/b/a Ameren Missouri) Gas Service Tariffs Removing Certain Provisions for Rebates from Its Missouri Energy Efficient Natural Gas Equipment and Building Shell Measure Rebate Program.	)))))))	File No. GT-2011-0410

AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael L. Stahlman, of lawful age, on his oath states: that he has participated in the preparation of the following Rebuttal Testimony in question and answer form, consisting of 16 pages of Rebuttal Testimony to be presented in the above case, that the answers in the following Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael L. Stahlman

Subscribed and sworn to before me this 8 day of September, 2011.

LAURA HOLSMAN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 21, 2015
Commission Number: 11203914

Laura Holsman
Notary Public

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UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. GT-2011-0410

I. Introduction

Q. Please state your name and business address.

A. Michael L. Stahlman, P.O. Box 360, Jefferson City, Missouri 65102.

Q. By whom are you employed and in what capacity?

A. I am a Regulatory Economist with the Missouri Public Service Commission (Commission).

Q. Have you previously filed testimony before the Commission?

A. Yes. I have filed testimony in Case No. GR-2010-0363.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address issues discussed by Union Electric Company d/b/a Ameren Missouri (Ameren Missouri or Company) witnesses, Mr. Gregory W. Lovett and Mr. Kyle Shoff in their direct testimonies. This testimony will also provide additional information about the energy efficiency programs as described in Section 6 of the Unanimous Stipulation and Agreement (Stipulation) in Case No. GR-2010-0363 (Energy Efficiency Programs) not included in either Mr. Lovett's or Mr. Shoff's direct testimonies.

II. Rebuttal of Mr. Lovett

Q. Do you agree with Mr. Lovett's assertion that the revised tariff sheets "remove measures which are not cost effective" (page 2, line 8)?

A. No, I do not. Mr. Lovett is asserting as fact that the measures Ameren Missouri proposes to remove are not cost-effective. Staff is not willing to make such a statement. The Stipulation requires a specific analysis of the energy efficiency measures which are listed in Appendix C to the Stipulation (attached hereto as Appendix C). The analysis required by paragraph 6.C. of the Stipulation to determine the effectiveness of the programs has yet to be completed.

Q. Do you agree with Mr. Lovett's assertion that terms of the Stipulation require Ameren Missouri to "...analyze the cost effectiveness of its current natural gas energy efficiency programs..." (page 2, lines 16-17)?

A. Yes, I agree that Ameren Missouri is to determine the cost-effectiveness of its Energy Efficiency Programs. However, paragraph 6.C. of the Stipulation requires: "The Company shall perform a **post-implementation** evaluation of the effectiveness of its non low income weatherization energy efficiency programs" (emphasis added). The Stipulation goes on to list additional requirements for performing this post-implementation evaluation. Specifically, in paragraph 6.C. on page 4 the Stipulation requires:

> Post-implementation evaluations of all programs or measures shall include usage data for program participants through the end of the month of April, 2012, and be completed by December 31, 2012. Post-implementation evaluations will generally be performed by an outside firm and include both a process evaluation and an impact evaluation.

In contrast to these requirements, Ameren Missouri's "evaluation" on which it is basing its proposal to remove certain measures from its tariff, was not conducted by an outside firm and does not include usage data through the end of the month of April, 2012 as required by the terms of the Stipulation.

Q. Do you agree with Mr. Lovett's statement that "Ameren Missouri's decision to analyze the cost effectiveness of its current natural gas energy efficiency programs was driven by the terms of the Unanimous Stipulation and Agreement in Case No. GR-2010-0363" (page 2, lines 16-18)?

A. No. If Ameren Missouri had concerns about the cost-effectiveness of the measures contained in Appendix C to the GR-2010-0363 Stipulation, it should have raised those issues during settlement discussions. Instead, Ameren Missouri raised the issue three months after it agreed to "provide for uninterrupted availability of these energy efficiency programs through December 31, 2012" as required by paragraph 6.G. of the Stipulation and three months after it began collecting $700,000 in rates for annual funding of Energy Efficiency Programs as provided in paragraph 2 of the Stipulation.

Q. Have the specimen tariff sheets in Attachment C to the Stipulation, *Missouri Energy Efficient Natural Gas Equipment and Building Shell Measure Rebate Program*, containing the measures of Ameren Missouri's Energy Efficiency Programs, been implemented?

A. Yes, Ameren Missouri filed the tariffs in accordance with paragraph 6.G. of the Stipulation and they became effective on February 20, 2011.

Q. Do you agree with Mr. Lovett's assertion in his direct testimony that "paragraph 6B of the Stipulation requires the Company to limit its energy efficiency funding to 'expenditures prudently-incurred on cost effective programs'" (page 2, lines 18-20)?

A. Yes, however the programs in question, attached as Appendix C to the Stipulation, have already been declared cost-effective with pre-implementation analysis in accordance with 4 CSR 240-14 Utility Promotional Practices rule, and 4 CSR 240-3.255 Filing Requirements for Gas Utility Promotional Practices in Case No. GR-2010-0363. The questions regarding the cost-effectiveness of measures raised by parties in the rate case were resolved and settled by the Stipulation and approved by the Commission as a resolution of Case No. GR-2010-0363.

Q. Is there any requirement, other than paragraph 6.C. of the Stipulation, for the Company to analyze the post-implementation cost-effectiveness of the programs?

A. No.

Q. Is there any requirement for the Company to reanalyze the pre-implementation cost-effectiveness?

A. No. Had Staff thought it necessary to perform a pre-implementation cost-effectiveness analysis of the measures and programs, Staff would have raised that issue and included that requirement in the Stipulation.

Q. Do you agree with Mr. Lovett's statement that "the Company was faced with the obligation to amend its tariffs to remove what it believed (and continues to believe) are non-cost effective measures" (page 4, lines 4-6)?

A. No. Per paragraph 6.G. of the Stipulation, the tariff sheets attached as Appendix C requires that Ameren Missouri: "shall provide for uninterrupted availability of these energy efficiency programs through December 31, 2012." Furthermore, paragraph 6.C. of the Stipulation requires post-implementation evaluations to "include usage data for program participants through the end of the month of April, 2012" and to "generally be performed by an outside firm and include both a process evaluation and an impact evaluation." The determination of cost-effectiveness should be based on a formal evaluation on more than speculative pre-implementation data in accordance with paragraph 6.C. of the Stipulation and not Ameren Missouri's "beliefs."

Q. Do you agree with Mr. Lovett's statement that "Paragraph 6G of the Stipulation allows Ameren Missouri to file revised tariff sheets if it believes the circumstances warrant changes after circulating those sheets for review by the [Energy Efficiency Advisory Group]" (page 4, lines 6-8)?

A. Yes, I agree that paragraph 6.G. does allow for Ameren Missouri to file revised sheets. This sentence was included because Staff realized that Ameren Missouri would have to file new measures to ramp up to meet the third year $850,000 target of paragraph 6.B. of the Stipulation. The purpose of this sentence was not to limit Ameren Missouri's measures to those listed in Appendix C of the Stipulation, but to allow Ameren Missouri to file revised tariff sheets in order to ramp up to the target in paragraph 6.B. Additionally, although Ameren Missouri may file revised sheets, this does not remove Staff's right to question the prudency of the changes to those tariff sheets per paragraph 6.D. of the Stipulation, nor does it remove the parties' other obligations under the Stipulation.

Q. Were the proposed tariff sheets in Ameren Missouri's tariff filing, JG-2011-0597, Ameren Missouri's energy efficiency tariff filing prior to the current case JG-2011-0620, filed on May 27, 2011 and then subsequently withdrawn, circulated to the

Energy Efficiency Advisory Group (EEAG) in accordance with paragraph 6.G. of the Stipulation?

A. No.

Q. Were the proposed tariff sheets in this tariff filing, JG-2011-0620 filed on June 8, 2011, circulated to the EEAG in accordance with paragraph 6.G. of the Stipulation?

A. No.

Q. Do you agree with Mr. Lovett's conclusion that "This tariff modification is required by the terms of the Stipulation because non-cost effective programs have been identified and is necessary so that Ameren Missouri can prudently administer its Natural Gas Energy Efficient Equipment programs" (page 5, lines 3-5)?

A. No. The prudent administration of the Energy Efficiency Programs is to evaluate the programs per paragraph 6.C. of the Stipulation on data gathered from the programs through April, 2012 and to comply with the terms of the Stipulation. This includes maintaining the uninterrupted availability of the programs, as shown in the specimen tariffs in Appendix C of the Stipulation, until December 31, 2012, in accordance with paragraph 6.G. of the Stipulation.

III. Rebuttal of Mr. Shoff

Q. Did Mr. Shoff "evaluate the cost-effectiveness of Ameren Missouri's natural gas energy efficiency portfolio" (page 2, lines 11-12) in accordance with paragraph 6.C. of the Stipulation?

A. No. Paragraph 6.C. of the Stipulation requires post-implementation evaluations to "include usage data for program participants through the end of the month of April, 2012" and to "generally be performed by an outside firm and include both a process evaluation and an impact evaluation." The measures in question, attached in Appendix C to the Stipulation, have already been declared cost-effective with pre-implementation analysis in accordance with 4 CSR 240-14, the Utility Promotional Practices rule, and 4 CSR 240-3.255, Filing Requirements for Gas Utility Promotional Practices. Questions of the parties regarding the evaluations of measures prior to the Stipulation were resolved and settled by the Stipulation approved by the Commission as a resolution of GR-2010-0363.

Q. Would Mr. Shoff be considered an outside firm?

A. No. On page 1, lines 9-12, Mr. Shoff identifies himself as a DSM Planning Consultant in the Corporate Planning Department of Ameren Services which is affiliated with Ameren Missouri.

Q. Did Mr. Shoff perform a process and impact evaluation as required by paragraph 6.C. of the Stipulation?

A. No. On page 2, line 12 Mr. Shoff states that to evaluate the portfolio, "[He] calculated [the Total Resource Cost test] for each measure and program."

Q. Do you agree with Mr. Shoff's definition of the Total Resource Cost Test on page 2, lines 15-22?

A. Staff would disagree with using any "proposed" tariff language as a retroactive basis for determining cost-effectiveness. Neither 4 CSR 240-14, 4 CSR 240-3.255, nor the Stipulation address the Total Resource Cost Test (TRC), nor does it allow it to be the sole determination as to whether a measure or program is cost-effective.

Q. Do you agree with Mr. Shoff that "A TRC ratio greater than 1.0 indicates that a measure is cost-effective" (page 2, line 22)?

A. I do agree that Mr. Shoff's pre-implementation TRC it is a measurement of cost-effectiveness but it should not necessarily be the sole determinant of whether a measure is cost-effective or not. The definition of cost-effective is defined in 4 CSR 240-14.010(D), the Utility Promotional Practices rule. "Cost-effective means that the present value of life-cycle benefits is greater than the present value of life-cycle costs to the provider of an energy service." There is nothing in any Commission rule regarding the cost-effectiveness of natural gas energy efficiency measures or programs nor does the Stipulation state that the TRC will be the sole criteria or address pre-implementation analysis.

Q. Do you agree with Mr. Shoff's statement on page 2, line 23, that the TRC can "be calculated at the measure level"?

A. Yes, however Mr. Shoff's analysis is contrary to the requirements of paragraph 6.C. of the Stipulation which requires post-implementation evaluations to "include usage data for program participants through the end of the month of April, 2012" and to "generally be performed by an outside firm and include both a process evaluation and an impact evaluation."

Q. Was Mr. Shoff's evaluation of Ameren Missouri's energy efficiency measures using "*ex-ante* savings and cost estimates" (page 3, line 18 emphasis added) consistent with the requirements of paragraph 6.C. of the Stipulation?

A. No. Mr. Shoff explains that:

> The measure level data was developed ***using best practice databases*** and, ***if available***, actual field data based on load

> reduction impact assessments from independent evaluation, measurement, and verification contractors. Missouri specific weather, Ameren Missouri specific building and heating/cooling system types, and Ameren Missouri specific building vintages (age of home) were applied as appropriate (emphasis added).

Paragraph 6.C. of the Stipulation requires post-implementation evaluations to "include usage data for ***program participants*** through the end of the month of April, 2012" (emphasis added). Using "*ex-ante* savings and cost estimates" (page 3, line 18) is typical of pre-implementation analysis, as noted in Mr. Shoff's direct testimony on page 6, lines 1-4. The pre-implementation analysis was completed for these measures under Case No. GR-2010-0363 in accordance with 4 CSR 240-14, the Utility Promotional Practices rule, and 4 CSR 240-3.255, Filing Requirements for Gas Utility Promotional Practices, and the measures and programs were determined to be cost-effective. Questions regarding the evaluations of measures prior to the Stipulation were resolved and settled by the Stipulation and approved by the Commission as a resolution of GR-2010-0363.

Q. Do you expect the cost-benefit ratio calculated on the building shell measures using actual data from the program participants to be different from the cost-benefit ratio that Mr. Shoff calculated *ex-ante*?

A. Yes. Mr. Shoff is basing his analysis on Ameren Missouri's *typical electric residential and commercial customers*. The program requires that, before Ameren Missouri provides a rebate for a measure, an audit must be performed on the residence and the measure must be shown to be cost-effective for the residence. Therefore, the likelihood that the measure will only be installed on Ameren Missouri's *typical electric residential and commercial customers* is very small which would result in a different cost-benefit ratio than what Mr. Shoff calculated *ex-ante*. This is why it is important to use post-implementation data to determine the cost-effectiveness of energy-efficiency measures and programs.

Q. Do you agree with the Company that measures with a pre-implementation TRC below one "should be removed from the natural gas programs" (page 3, lines 22-23)?

A. No. Per paragraph 6.G. of the Stipulation, the specimen tariff sheets attached as Appendix C "shall provide for uninterrupted availability of these energy efficiency programs through December 31, 2012." There is nothing in the rules regarding natural gas energy efficiency or in the Stipulation that states that the TRC will be the sole criteria for determining whether or not a measure is retained in the program. Further, Mr. Shoff's analysis is contrary to the requirements of paragraph 6.C. of the Stipulation which requires **post-implementation** evaluations to "include usage data for program participants through the end of the month of April, 2012" and to "generally be performed by an outside firm and include both a process evaluation and an impact evaluation."

Q. Do you agree with Mr. Shoff that "a program is a bundle of measures" (page 5, line 13)?

A. Yes. The programs consist of measures and are to be uninterruptedly available through December 31, 2012, per paragraph 6.G. of the Stipulation.

Q. Do you agree with Mr. Shoff that the TRC test would be "considered best practices for estimating the cost-effectiveness of energy efficiency measure, programs, and portfolios" (page 5, lines 20-21)?

A. No, I do not. 4 CSR 240-14, 4 CSR 240-3.255 and the Stipulation do not address the TRC. Additionally, Mr. Shoff's analysis does not "include usage data for program participants through the end of the month of April, 2012" and was not "performed by an outside firm and include both a process evaluation and an impact evaluation."

Q. Do you agree with Mr. Shoff that the "TRC is the de facto standard in the NAPEE guide *'Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues For Policy-Makers'* dated November 2008" (page 6, lines 14-17)?

A. No. "De facto" is defined in Webster's New World Dictionary as "existing or being such in actual fact though not by legal establishment." However, a cursory look at the National Action Plan for Energy Efficiency (NAPEE) guide referenced by Mr. Shoff (attached as Appendix B) references five different tests as the "standard" tests. In fact, on the first page of its Executive Summary, it states: "There is no single best test for evaluating the cost-effectiveness of energy efficiency". I did not see a statement in that document where it refers to the TRC as the "de facto standard."

Q. Do you agree with Mr. Shoff that "There are resources in both the public and private domains...that capture the essence of measure level savings energy savings on an *ex ante* basis" (page 6, lines 18-20)?

A. Yes. However, Mr. Shoff defines "*ex ante*" as "before implementation" on page 6, line 2 of his direct testimony. As mentioned above, the measures and programs examined by Mr. Shoff and attached as Appendix C to the Stipulation were considered to be cost-effective and were included in programs implemented as required by paragraph 6.G. of the Stipulation. Thus these programs should be examined on an *ex post* basis, defined by Mr. Shoff as "after implementation" on page 6, line 2, and including "usage data for program participants through the end of the month of April, 2012" as required by paragraph 6.C.of the Stipulation.

Q. Do you agree with Mr. Shoff that "the Commission does not have specific rules for natural gas energy efficiency programs" (page 7, lines 4-5)?

A. No. Staff concedes there are no specific Commission rules for energy-efficiency programs specific to natural gas. However, 4 CSR 240-14, the Utility Promotional Practices rule and 4 CSR 240-3.255 Filing Requirements for Gas Utility Promotional Practices rule apply to natural gas demand-side programs which include energy-efficiency programs.

Q. Do you agree with Mr. Shoff that "cost-effectiveness should [not] be measured differently for natural gas and electricity" (page 7, lines 8-10)?

A. No. Mr. Shoff references rule 4 CSR 240-22.050 Demand-Side Analysis of Chapter 22 Electric Utility Resource Planning just prior to that statement. The Electric Utility Resource Planning Chapter does not apply to natural gas. Natural gas resource utility planning is different from electric utility planning in that natural gas companies deliver a commodity directly to its customers where as electric companies take a commodity to generate electricity to deliver to their customers. Staff does not believe it is reasonable to apply select portions of the electric rule ad hoc in natural gas.

Q. Do you agree with Mr. Shoff that, "it [is] common to use *ex ante* measure level savings values to estimate the cost-effectiveness of programs" (Shoff Direct page 7, lines 11-13)?

A. It is common for pre-implementation analysis which was completed for these measures under Case No. GR-2010-0363 in accordance with 4 CSR 240-14, the Utility Promotional Practices rule, and 4 CSR 240-3.255, Filing Requirements for Gas Utility Promotional Practices. However, post-implementation analysis requires "[ex post] usage data for program participants through the end of the month of April, 2012" by paragraph 6.C. of the Stipulation.

Q. Do you agree with Mr. Shoff assertion that 76 percent of all respondents to an American Gas Association (AGA) and Consortium for Energy Efficiency survey of member utilities used "the TRC as the primary evaluation tool for energy efficiency programs" (page 8, lines 8-9)?

A. No, a cursory look at the AGA "Natural Gas Programs Report: 2009 Program Year" (attached as Appendix A) cites the TRC as a common test on page 24; however it does **not** state that the TRC was the **sole** criterion. That AGA report does not discuss primary evaluation tools. However, a brief look at the NAPEE guide, "*Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*" (2008) reveals that it does discuss primary cost-effectiveness tests in Tables 5-1 and 5-3. The tables indicate that while six out of fifty states and the District of Columbia use the TRC as the primary test, it is much more common to not specify a primary cost-effectiveness test. The NAPEE "*Guide to Resource Planning with Energy Efficiency*" (2007) does state, "Thus, regulators of most states use the TRC as the primary cost test for evaluating their energy efficiency programs" (pages 5-3), but it is unclear what analysis, if any, NAPEE did to justify that statement and this statement contradicts the analysis in NAPEE (2008).

Q. Was the TRC designed to be the sole method used to determine cost-effectiveness?

A. No. The previously cited NAPEE guide states that there are five standard tests, which originated with the California Standard Practice Manual (attached as Appendix D). A cursory look at the California Standard Practice Manual shows that,

> The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests." (page 6)

Q. Do you agree with Mr. Shoff that "the TRC test is the best method to evaluate the cost-effectiveness of natural gas energy efficiency measures and programs" (page 8, lines 17-19)?

A. No, I do not. The TRC is one of a group of standard tests. Staff does not rely on just one test to evaluate the cost-effectiveness of a measure or program. Staff looks forward to reviewing the results of the TRC and other cost-effectiveness tests that meet the requirements of paragraph 6.C. of the Stipulation which requires post-implementation evaluations to "include usage data for program participants through the end of the month of April, 2012" and to "generally be performed by an outside firm and include both a process evaluation and an impact evaluation" are met.

Q. Do you agree that "Ameren Missouri utilized best-practice approaches in conducting its cost-effectiveness screening" (page 2, lines 4-5)?

A. No. It is Staff's position that the best-practice approach includes evaluating the programs in accordance with the Stipulation.

IV. Additional Information

Q. Is Ameren Missouri collecting money in rates to fund the Energy Efficiency Programs?

A. Yes. Per paragraphs 2 and 6.A. of the Stipulation, the Company is receiving $700,000 in annual funding from rates for Energy Efficiency Programs; $263,000 of which is to be used for low income weatherization programs leaving $437,000 for non-low income weatherization energy efficiency programs.

Q. Did Ameren Missouri agree in the Stipulation to ramp up spending on Energy Efficiency Programs?

A. Yes. Per paragraph 6.B. of the Stipulation, Ameren Missouri agreed to ramp up spending over three years to a target level of approximately $850,000.

Q. How much money has Ameren Missouri spent on the Energy Efficiency Programs since the new tariffs came into effect on February 20, 2011?

A. In response to a Staff data request, the Company indicated that expenditures on the current non-low income weatherization programs that became effective February 20, 2011 are $64,217. Of this amount, $39,734 was rebated for the measures that the Company is now seeking to remove from its program.

Q. If Ameren Missouri keeps all the current measures, is it likely to exceed the $437,000 they are currently collecting in rates?

A. No. Ameren Missouri's Quarterly Update indicates that as of the end of the second quarter, if the assumption is made that all program reservations are paid in full, Ameren Missouri has spent less than one third of the money collected in rates.

Unless expenditures double for the next two quarters Ameren will not rebate $437,000 to its customers.

V. Conclusion

Q. What is Staff's recommendation?

A. Staff recommends that the Commission reject Ameren Missouri's proposed tariff sheets since they contradict the terms of the Commission Approved Unanimous Stipulation and Agreement for Case No. GR-2010-0363.

Q. Does this end your testimony?

A. Yes it does.

Natural Gas Efficiency Programs Report

2009 Program Year

Prepared by
Policy Analysis Group
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400 N. Capitol St., NW
Washington, DC 20001
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AGA
American Gas Association

November 2010

Appendix A

Contents

INTRODUCTION

Awareness of the energy economy has steadily grown beyond the purview of business and public policy. Economic and environmental concerns have become increasingly important drivers of consumer decisions about energy. With this has come heightened attention to the potential for energy efficiency to moderate consumer cost increases, reduce greenhouse gas emissions and enhance energy security. For natural gas distributors, investing in natural gas efficiency programs presents an opportunity to achieve these objectives and benefit the communities they serve. Many have long-performing natural gas efficiency programs, while others are working with their regulators to pave the way for new programs that will accelerate progress towards realizing a clean energy future while building sustainable value for their businesses and customers.

The *AGA Natural Gas Efficiency Programs Report - 2009 Program Year* presents data collected from members of the American Gas Association and the Consortium for Energy Efficiency[1] on ratepayer-funded natural gas efficiency and conservation programs. The report aims to portray the extent of this rapidly growing market in the United States and Canada and to identify practices and trends in program planning, funding, administration and evaluation.

This fourth annual study looks retrospectively at the status of the natural gas efficiency market in 2009, including expenditures and savings impacts, and presents a snapshot of budgets for 2010. Also explored are regulatory approaches to advancing the natural gas efficiency market. The findings illustrate how natural gas utilities have worked with their customers to help them reduce their carbon footprint and increase cost savings and with their regulators to bring about progressive policies that support such initiatives.

An important contributor to this data gathering project is the Consortium for Energy Efficiency (CEE). The data collection effort has expanded significantly since AGA and CEE began coordinating collection of these data in 2009. By joining forces, AGA and CEE have reduced the reporting burden for respondents, eliminated duplicative efforts for our organizations, and significantly enlarged the sample pool—extending the survey to more utilities in the U.S. and Canada and to third-party administrators of ratepayer-funded efficiency programs.

AGA would like to thank the members of AGA and CEE in the U.S. and Canada for participating in this important data-collection effort. We appreciate tremendously the time and effort given by all survey respondents throughout the data collection process, including extensive clarification and data validation follow up. (See Appendix E for a listing of participating companies).

[1] The Consortium for Energy Efficiency (www.cee.org) is a nonprofit public benefits corporation that develops initiatives for its North American members to promote the manufacture and purchase of energy-efficient products and services. CEE members include utilities, statewide and regional market transformation administrators, environmental groups, research organizations and state energy offices in the U.S. and Canada.

Executive Summary

In 2010 the American Gas Association (AGA) and the Consortium for Energy Efficiency (CEE) surveyed their U.S. and Canadian members and other efficiency program administrators on the status of their 2009 *ratepayer-funded* natural gas efficiency programs, including low-income weatherization. Based on survey findings for the 2009 program year:

- By investing in successful and innovative efficiency programs—which include strategic partnerships, education campaigns, targeted marketing, low-income usage programs, energy audits, whole house projects, customer rebates and incentives, and customized retrofits of large facilities—natural gas utilities continue to help their customers to reduce energy usage and lower annual energy bills.

- Natural gas utilities fund 111 natural gas efficiency programs—106 in 38 states and five in Canada. U.S. utilities plan to launch six new programs in 2010.

- Residential natural gas efficiency program participants in the U.S. saved on average nine percent of usage or about 69 Therm per year, averaging $83 in cost saving on their annual energy bill.

- In the United States, utilities invested nearly $803 million in natural gas efficiency programs in 2009 and have budgeted about $1.1 billion in 2010. This represents a 42 percent increase[2].

- Natural gas efficiency program expenditures approached $870 million in North America in 2009, and they are estimated to grow to more than $1.2 billion in 2010 (a 41 percent increase).

- Utilities spent from 0.01 to 9.5 percent of net natural gas distribution revenues (net of gas costs) on natural gas efficiency programs in 2009.

- In 2009 U.S. customers saved nearly 53 trillion Btu through natural gas efficiency programs (a nine percent increase from 48 trillion Btu in 2008[3]), thus avoiding 2.8 million metric tons of carbon dioxide (CO_2) emissions.

- Natural gas savings impacts from efficiency programs reached nearly 90 trillion Btu in North America, an 11 percent increase from 81 trillion Btu in 2008 and the equivalence of 4.7 million metric tons of avoided CO_2 emissions.

- Eighty-five percent of natural gas efficiency programs provide conservation or energy efficiency activities to low-income customers.

- Twenty-eight states require that utilities fund natural gas efficiency programs, and 25 states mandate that utilities implement programs specific to low-income customers.

- Thirty-four states allow utilities to recover natural gas efficiency direct program costs, 23 permit them to recoup lost margins, and 12 approve financial incentives for utilities based on program implementation and performance.

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[2] The 2009 and 2010 survey samples are similar; however, 2010 budgets include data for six newly launched programs.

[3] Natural gas efficiency program savings for the 2008 program year have been revised for the U.S. and Canada since this report was last published in December 2009.

- Recovery of natural gas efficiency direct program costs are allowed via the following mechanisms:
    - special tariff or rider in 25 states
    - base rates in 13 states
    - system benefits surcharge in eleven states
    - other mechanism in four states.
- Sixteen percent of regulator-approved natural gas efficiency programs encourage fuel switching, and 14 percent measure efficiency from the energy source to the usage site by applying a full fuel cycle analysis.
- U.S. spending on evaluation, measurement and verification activities surpassed $12 million in 2009, and it is estimated to approach $31 million in 2010 (a 150 percent increase).

METHODOLOGY AND SURVEY SAMPLE

In 2010 the American Gas Association (AGA) and the Consortium for Energy Efficiency (CEE) surveyed their U.S. and Canadian members and other efficiency program administrators on the status of their 2009 *ratepayer-funded* natural gas efficiency programs, including low-income weatherization[4]. Also included are data from non-utility or "third-party" administrators of utility funded natural gas efficiency programs[5]. In this report, the term "natural gas efficiency program" refers to a set of activities designed to promote a cost-effective and prudent approach to energy usage, including single and multifamily residential low-income weatherization; indirect impact activities; and new and existing building direct impact activities (see page 8 for examples of such activities).

The sample frame consisted of all member organizations of AGA and CEE and nonmember organizations identified as large program administrators. The response rate was 88 percent. Therefore, natural gas efficiency statistics may be understated in this report. Responses were received for 106 programs implemented in the U.S. in 2009 and five in Canada. We also received responses for six U.S. programs planned for 2010. Two variations of the survey were distributed: 1) a short form (which focuses on natural gas efficiency program funding and savings impacts) was distributed primarily to CEE members, including administrators of statewide energy programs; and 2) a long form (which includes questions on program characteristics, expenditures, budgets, evaluation and regulatory treatment) was distributed to all AGA members. The introductory part of this report and part II encompass all collected data from short and long forms, and the remainder discusses responses from a subset of companies that completed the long form (92 companies in the U.S. and two in Canada).

The gas utilities represented in this report (including those that fund third-party programs) have natural gas service territories in 38 states and Canada. These utilities account for nearly 69 percent of the natural gas delivered by gas distribution companies in the United States, which have an aggregate annual U.S. throughput of 9.2 trillion cubic feet (Tcf)[6]. These companies also served more than 45 million residential customers cumulatively, corresponding to 69 percent of the U.S. residential natural gas market.

The survey asked respondents to describe their natural gas efficiency programs during the 2009 calendar year (or coinciding program year for which data were available). Also, 2010 data were collected for approved natural gas efficiency program budgets and estimated participant counts. Not all reporting companies answered every question on the survey. The sample therefore varies question to question. Because the sample pool is not normalized and varies year to year, this report does not directly compare 2009 with prior year data, except for illustrative purposes when discussing program expenditures and savings impacts. Tables and charts represent a simple tally of the responses to the survey questionnaire.

Report footnotes and section introductions provide additional information regarding methodology.

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[4] Because many low-income weatherization programs are run by non-participating state agencies, report data understate low-income programs budgets.

[5] Appendix E lists the companies represented in this report, including those that did not respond directly but whose data were provided by third-party administrators. While only aggregate information is presented in the report, Appendix B, C and D present data at a state and/or region level only for companies that agreed to release their information.

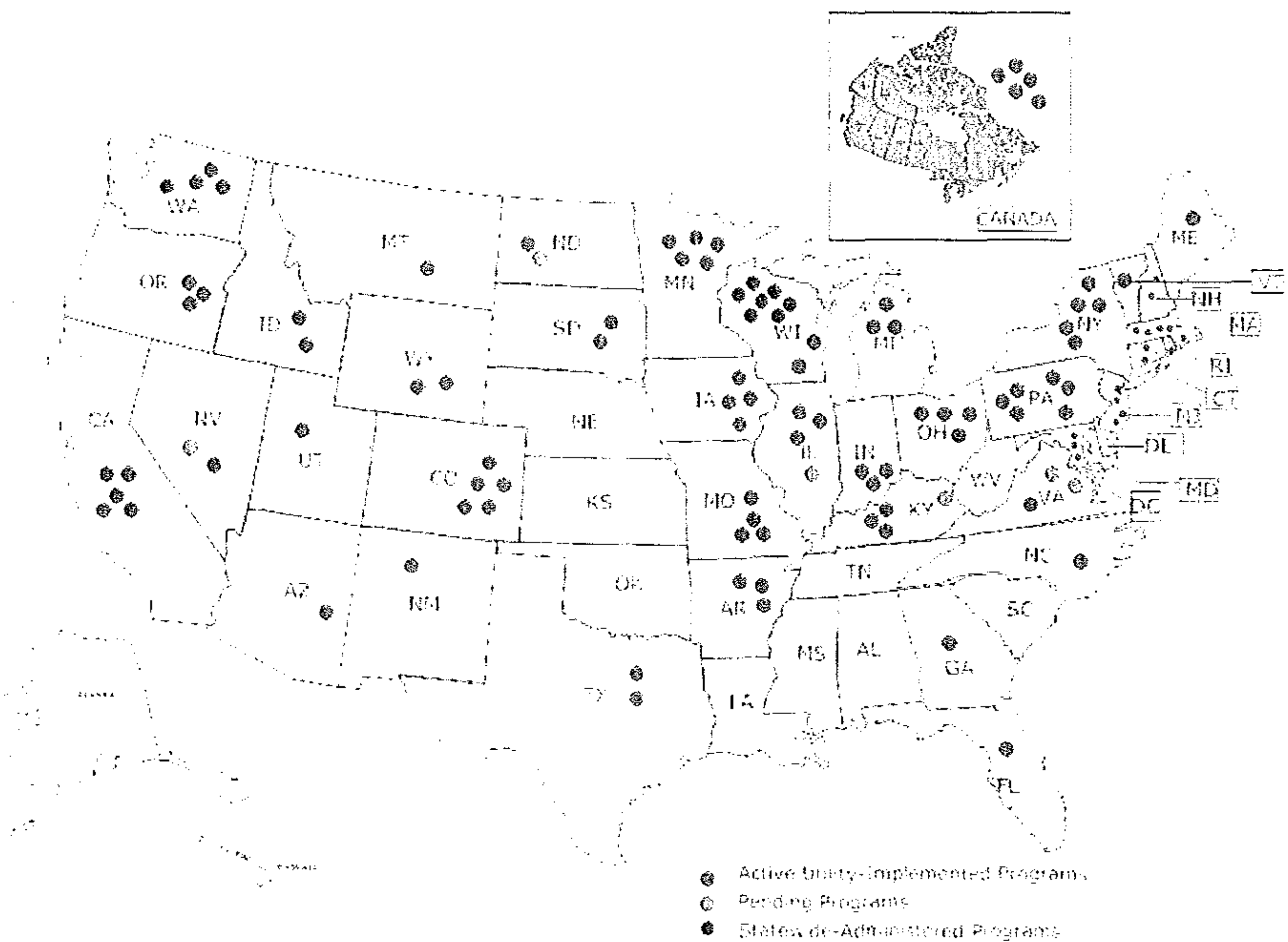
[6] Based on Energy Information Administration consumption data: Natural Gas Annual 2008 (Released March 2010)

I. Natural Gas Efficiency Program Characteristics

According to 2009 program year data, there are at least 111 active natural gas efficiency programs in North America—106 in the U.S. and five in Canada—that are funded by local natural gas utilities. Utilities also plan to launch six new programs in the U.S. in 2010 (see Figure 1).

Figure 1

Utility-Funded Natural Gas Efficiency Programs
(111 Active & 6 Planned Programs in 38 States & Canada in 2009)



The 106 U.S. programs include 98 that are administered by utilities (in part or whole) and eight that are implemented solely by a third-party agency, generally as part of a collaborative, such as the Energy Trust of Oregon, New Jersey Clean Energy Program, New York State Energy Research and Development Authority, and Wisconsin Focus on Energy. Ten of the 98 utilities fund third-party administered programs in conjunction with their own utility-implemented programs; however, to avoid double-counting, these are not counted separately in this report.

Program Structure

From this point forward, except in part II, Natural Gas Efficiency Program Funding and Impacts, this report describes a subset of utility-implemented natural gas efficiency programs for which a more comprehensive set of data was obtained. This subset comprises 94 programs (92 in the U.S. and two in Canada) implemented by 52 natural gas distributors, 40 combination gas-electric utilities and two municipally-owned utilities (see Table 1).

Table 1

NATURAL GAS EFFICIENCY PROGRAM BY UTILITY TYPE		
COMPANY TYPE	PROGRAMS	PERCENTAGE
Investor-Owned Natural Gas Distributor	52	55%
Investor-Owned Gas & Electric Utility	40	43%
Municipally-Owned Utility	2	2%
TOTAL	94	100%

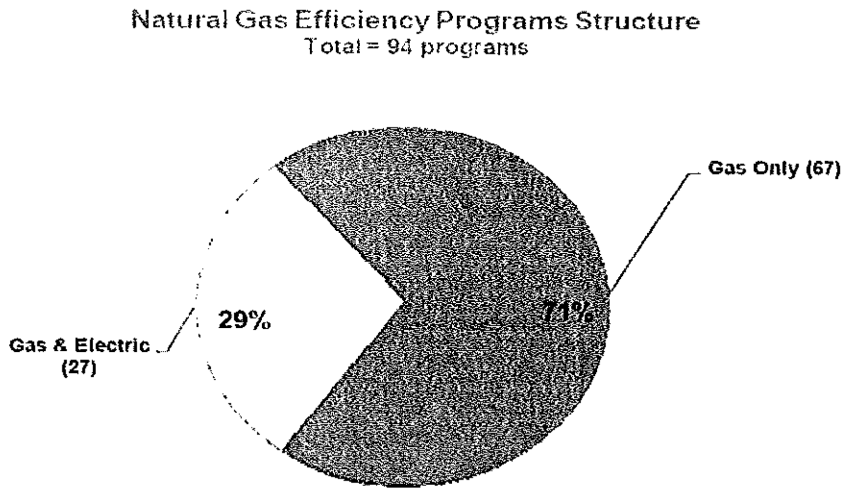
Of the 94 natural gas efficiency programs, 72 are administered solely by the utility, two by a government agency, five by a nonprofit organization, and 15 by more than one entity. This latter category includes utilities that administer their own programs while funding statewide programs; support community action programs in implementing low-income programs; and/or outsource the delivery of specific activities (such as rebate processing, energy audits or education programs) to third-party nonprofit or for-profit firms (see Table 2).

Table 2

NATURAL GAS EFFICIENCY PROGRAMS ADMINISTRATION		
	PROGRAMS	PERCENTAGE
Utility-Administered	72	77%
Nonprofit Organization	5	5%
Government Agency	2	2%
Other or a Combination of Entities	15	16%
TOTAL	94	100%

The majority of natural gas efficiency programs (67 out of 94) are administered as natural gas-only, while 27 are combined with electric efficiency programs (see Figure 2). Forty-two of 93 respondents (45 percent) reported that they coordinate efficiency activities with other organizations or utilities (natural gas, electric or combination), thereby reducing costs and ensuring consistency in program offerings and delivery.

Figure 2



Gas Efficiency Program Characteristics

Natural gas efficiency programs average 10 years of service, ranging from newly launched to mature programs that span 20 or more years, and nearly all have run without interruption since inception. Forty-six percent have been in place for 10 years or longer (see Table 3).

Table 3

Natural Gas Efficiency Programs Since Inception	
Years of Service	Number of Programs
Less than 1 (2009 start)	16
1 ≥ < 10	35
10 ≥ < 20	22
20 or more	21
TOTAL	94

Forty-five percent of natural gas efficiency programs (42 of 93) grew since the 2008 program year. Utilities accomplished this by targeting new markets and customer classes, increasing funding and participation levels, and developing new programs (such as Home Performance with Energy Star, building operator certification and new commercial construction). They also expanded low-income weatherization programs to include no-cost and low-cost equipment replacement programs, enhanced outreach (via marketing and conservation education), boosted rebate programs by augmenting rebate amounts or adding new measures, and piloted new technologies.

Objectives

When asked to select all goals that drive their natural gas efficiency programs, respondents identified them as follows: 98 percent target direct impact on energy savings; 85 percent engage in behavioral change (with education, training or direct outreach to customers and others); 65 percent seek market transformation (through manufacturers, distributors, retailers and consumers of energy-related products and service); and 43 percent aim for avoided emissions. Thirty-five percent (33 out of 94) maintain that all four goals drive their programs. Also fourteen percent sited other or supplementary goals, including economic development and job creation; reducing households' energy burden; assisting hard-to-reach markets under distress; reducing uncollectible expenses due to write offs of arrears for low-income customers; moderating growth in electric consumption and dependence on other fuels; and avoiding system transmission capacity upgrades (see Table 4).

Table 4

Purpose or Goal of Natural Gas Efficiency Program (94 natural gas efficiency programs with one or more goals)		
Goal	Number of Programs	Percentage
Direct Impact on Energy Savings	92	98%
Behavior Change	80	85%
Market Transformation	61	65%
Direct Impact on Avoided Emissions	40	43%
Other	13	14%

Customer Segments

Respondents were asked to identify all customer classes included in their natural gas efficiency programs. Eighty-seven percent of programs (82 of 94) provide natural gas efficiency and conservation services to residential customers, 84 percent (79 programs) to low-income customers, and 69 percent (or 65 programs) to small commercial and industrial (C&I) customers. Six of the 94 respondents offer natural gas efficiency measures only to residential customers, eleven provide only programs specific to low-income customers, and one program has only C&I efficiency activities. Fifty-nine percent (or 55 programs) include all customer classes in their natural gas efficiency programs.

Participant counts were obtained for 70 active natural gas efficiency programs in 2009, and estimated counts were gathered for 70 programs in 2010. Many programs do not track or report participation rates, while others had low to no participation in 2009 due to late program implementation. In cases where respondents do not actively monitor participants, they provided estimated instead of exact counts. Also some program administrators keep track of processed rebates and installed measures or projects instead of tallying enrolled customers. Methodology approaches vary regarding whether to count online audits and students participating in school-based education programs. Thus participant figures should be regarded as very rough estimates.

During 2009, 1,287,561 residential customers, 256,133 low-income participants, and 44,942 C&I customers were enrolled in natural gas efficiency programs. The median count is 3,457 participants in residential programs, ranging from as few as 15 to as many as 326,943 customers. For low-income programs, ranging from 1 to 100,340 participants, the median customer count is 319. C&I programs have from four to 15,672 accounts, and the median count is 107 accounts. Two million participants are estimated for the 2010 program year of which 1,678,789 are residential, 416,053 are low income, and 59,151 are C&I customers.

Survey respondents were asked to identify all natural gas efficiency activities offered to customers in each sector. Based on data reported for 94 programs, the majority provide indirect and direct impact efficiency services to all or several customer segments. These activities are provided to residential single family homes in 81 programs, multi-family housing in 69 programs, low-income homes in 80 programs, and C&I customers in 65 programs. Thus 85 percent of utility-implemented programs offer low income customers conservation and efficiency activities, including weatherization measures (in 71 percent of programs).

When asked whether they offered enhancements for low-income qualified programs, 79 percent of respondents (73 of 92) indicated that this customer segment does have access to a portfolio of programs exclusively available to them. Nineteen of these enhanced low-income programs are administered by the utility, 17 by a community action agency, three by the state, and 33 by another entity or jointly among several entities. These coordinated efforts include joint delivery of gas and electric low-income efficiency programs. Also several utilities that do not administer their own low-income efficiency activities provide funding to state-implemented low-income programs.

Services and Products

As shown in Table 5, besides low-income customers, the residential single family and residential multi-family customer segments benefit from weatherization services in 48 and 37 percent of programs respectively. Indirect impact activities are also offered to one or more customer segments, and these include customer education (in 74 percent of programs), online tools (68 percent), technical assessments or energy audits (56 percent), and contractor and building operator training and certification (41 percent). Programs also offer direct impact efficiency measures to existing residential single family homes (in 78 percent of programs), multi-family housing (66 percent), low income homes (75 percent), and C&I properties (66 percent). These direct impact activities include equipment replacement and upgrades (e.g., appliances, doors, windows, and thermostats), building retrofits, commercial food service, process equipment, energy management systems and custom process improvements. Direct impact activities are also available for new buildings and expansions, and these include energy efficient homes, energy efficiency design assistance, and industrial efficiency. Other activities include residential school-based education programs, low income instituted test measures for new technologies, commercial nonprofit weatherization, and custom prescriptive programs.

Table 5

Utility-Implemented Natural Gas Efficiency Program Activities by Customer Class
Total = 94 reporting EE programs with one or more EE activities

Energy Efficiency Activities	Residential Single Family 81 Programs	Residential Multi-Family 69 Programs	Residential Low Income 80 Programs	C & I 65 Programs
Weatherization	45	35	67	
Indirect Impact Programs Certification	17	12	17	13
Education	69	49	61	53
Online Tools	63	40	45	41
Technical Assessment	52	35	49	41
Training	35	26	29	38
Direct Impact Programs – Existing Buildings	73	61	70	61
Direct Impact Programs – New Construction/Expansion	45	26	22	37
Other	5	2	3	4

When asked to identify all products offered in their residential natural gas efficiency programs, 92 respondents selected furnaces (in 81 programs), boilers (67), comprehensive whole house efficiency (for existing homes in 66 programs and for new construction in 44 programs), storage water heaters (65), tankless water heaters (53), tune ups and controls upgrades (38), HVAC quality installation (32), clothes washers (23), windows (14), dishwashers (9) and solar water heaters (7). C&I programs include boilers (59 programs), furnaces (59), storage water heaters (55), tankless water heaters (45), tune ups and controls upgrades (44), commercial kitchens (42), HVAC quality installation (24), energy management or continuous energy improvement (19), and solar water heaters (13). Several programs also offer separate industrial programs that are either custom (40 programs), prescriptive (29) or include plant assessments (25).

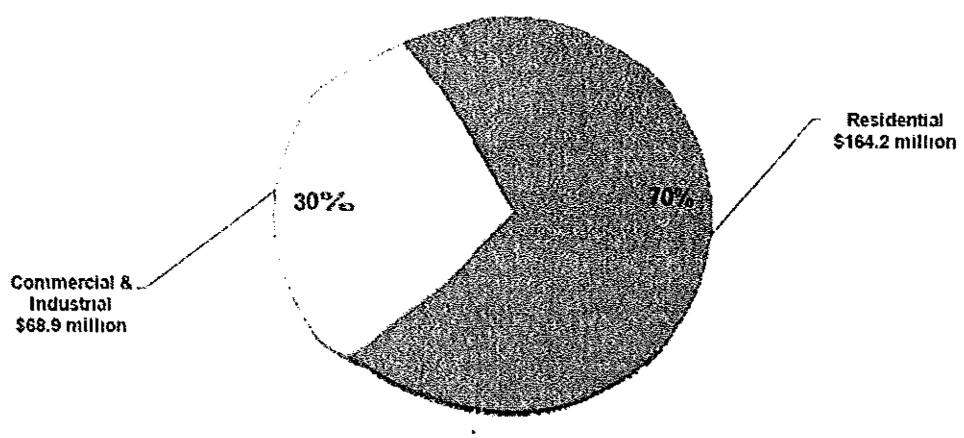
Other products were listed by 29 respondents, including programmable thermostats, radiant heaters, and drain water heat recovery. Additional residential products include chimney dampers, low-flow faucet aerators and showerheads, pilot-less hearth, and air duct sealing and attic insulation. Additional C&I products include rooftop gas pack units; prescriptive gas cooling; custom gas engine drives; boiler tune ups; steam traps; vent dampers; low-flow pre-rinse spray nozzle; new construction energy design assistance; retro commissioning of gas building controls; energy audits; engineering studies; commercial kitchen griddles, steamers, fryers, combination ovens, and modulating burners; and combined heat and power distributed generation.

Customer Incentives

Many natural gas efficiency programs offer customers financial incentives toward energy savings, such as appliance rebates and equipment financing. Respondents reported an aggregate 2009 annual incentive budget of $164 million for 66 residential programs and $69 million for 44 C&I programs (see Figure 3). The estimated incentive budget for 2010 is $241 million for 74 residential programs and $157 million for 59 C&I programs (including budgets for newly launched 2010 programs).

Figure 3

Natural Gas Efficiency Program Customer Incentive Budgets by Sector



Eighty-one percent of natural gas efficiency programs (75 of 93) offer their customers cash incentives for high-efficiency natural gas appliance installations. Of those that have rebate programs, 97 percent offer them to residential customers, 72 percent to commercial customers and 52 percent to small industrial customers. Forty-three percent of the residential rebates are used by low-income customers. Thirty-two percent (or 24 programs) offer rebates to all customer classes. As seen in Table 6, rebate dollar amounts vary widely, depending on the type and number of measures.

Table 6

Gas Appliance Rebates Programs					
	Boilers	Furnaces	Water Heaters	Programmable Thermostats	Other
Residential (70 Responses)					
Available Programs	53	67	59	45	27
Dollar Range	$75 $1,400	$75 $1,600	$35 $900	$10 $50	$10 $1,300
Low Income (28 Responses)					
Available Programs	25	28	26	22	14
Dollar Range	$150 $3,500	$100 $2,500	$50 $1,400	$20 $300	$20 $50,000
Commercial (50 Responses)					
Available Programs	40	42	38	25	23
Dollar Range	$75 $50,000	$75 $50,000	$30 $50,000	$20 $50	$30 $5,000
Industrial (24 Responses)					
Available Programs	20	22		12	12
Dollar Range	$150 $50,000	$100 $50,000		$25 $50	$200 $500,000

Customers are normally required to submit rebate forms with required documentation to qualify for reimbursement. As a pre-requisite to accessing rebates, some programs require their customers to accept a free energy audit (and include a programmable thermostat and weatherization kit for residential customers). This helps encourage a whole house or whole system approach to efficiency. Often programs vary the value of the rebate or incentive, based on the efficiency rating of the replacement appliance or efficiency savings of the project.

Eligible appliances for residential cash rebates include high-efficiency boilers (53), furnaces (67), storage and tankless water heaters (59 programs), and programmable thermostats (45). In 27 residential programs, other measures are offered, including insulation and sealing, ranges, clothes washers, dryers, dishwashers, combined space and water heating units, drain water heat recovery, new construction Energy Star Homes and Energy Star windows, boiler reset controls, shower heads, free weatherization kits, and free thermostats.

Income-qualified rebate programs also cover Energy Star windows, insulation, combination space and water heating systems, dishwashers, clothes washers, dryers and drain water heat recovery. Some programs double the rebate amount for low-income customers, offer them free energy audits, or help with loans through a community bank. Furthermore, several programs supplant rebates to low-income customers by paying the full cost of high-efficiency measures, including appliance repairs and replacements. In other low-income programs, the utility pays up to 90 percent of the total installation costs, capped at a specific dollar limit. Still others include the full appliance replacement cost only if it can be justified by the energy savings, health and safety criteria or pass a Total Resource Cost test.

For C&I programs, the rebate amount varies even more widely than in residential programs. Some incentive reimbursements consist of a set dollar amount per high-efficiency appliance unit; some involve a percentage of total insulation or equipment purchase cost, capped at a specific dollar amount; while others have a specific dollar amount per square footage or Therm saved. In some programs, the reimbursement is a percentage of the incremental cost of adopting a higher efficiency standard for a particular measure. In others, bigger incentives are provided to larger volume customers for adopting higher-efficiency measures. Many of the C&I rebates are awarded on a custom, or site-specific, basis.

Other measures that qualify for rebates in C&I programs include insulation and sealing, direct-fired heaters, integrated water heating and condensing boilers, gas cooling, combined heat and power, chillers, boiler tune ups, infrared heat, pre-rinse sprayers, steam traps, drain water heat recovery, system/water clothes washers, food service equipment including Energy Star gas fryers, steamers, ovens, ranges, and griddles.

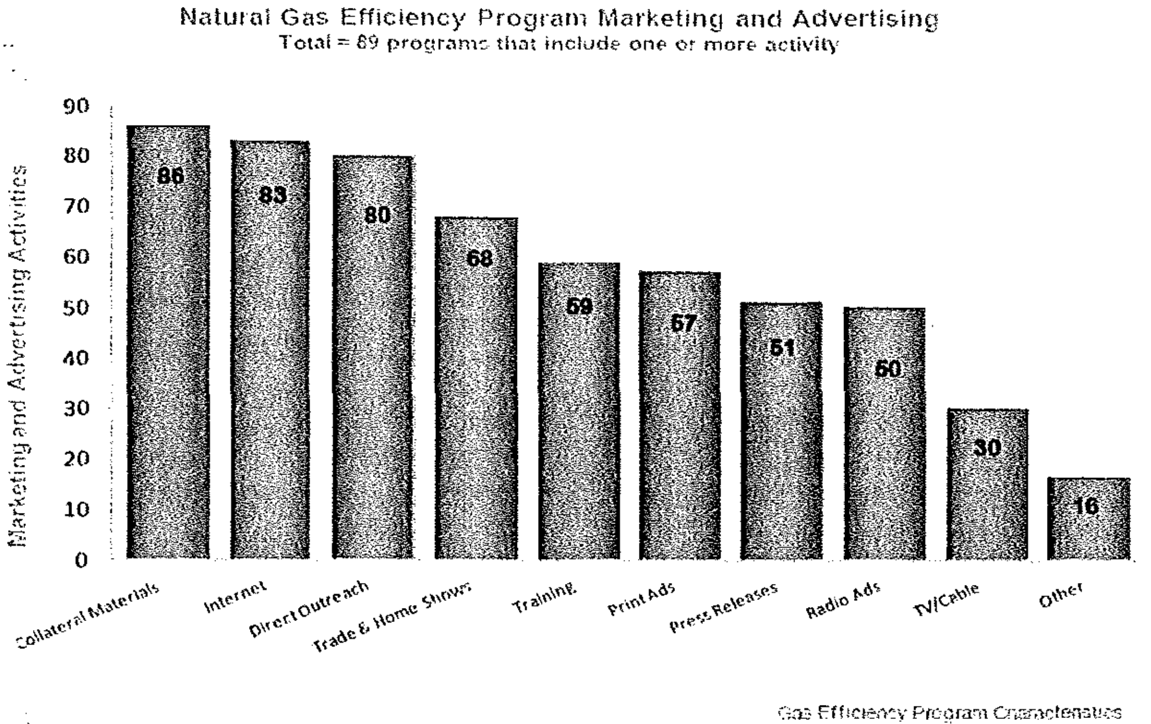
A number of programs help customers finance high-efficiency natural gas appliance purchases. Nineteen percent (18 of 94) grant these loans to qualifying customers. One program leverages and helps promote financing that is administered by neighboring electric companies. Of the 18 programs, 14 offer financing to residential customers, ten to commercial customers, and three to industrial customers. Three of those offer loans to all customer classes.

Six of the 18 programs offer interest-free loans; four provide interest rate buy-down and two include both. Six programs have other types of loans, such as low-fixed rates and other annual percentage rates. Fifty percent of these programs (9 of 18) administer loans in house, while 44 percent (8 programs) assign loan processing to a third-party. Only one program splits loan administration between in-house staff and an outside consultant. Six of the 18 programs (or 33 percent) use on-bill financing, where loan installments are added directly to a qualifying customer's monthly bill.

Ninety-five percent of natural gas efficiency programs (89 of 94) are promoted via an array of marketing and outreach efforts in the form of collateral materials, internet tools, direct outreach, trade and home show promotions, training, print ads, press releases, radio commercials and/or TV and cable advertisements. Twenty-three percent of programs (20 of 88) employ all these approaches

As seen in Figure 4, the most widely used approach is the distribution of collateral materials (e.g., brochures and bill inserts), followed closely by internet tools and direct outreach.

Figure 4



Sixty-seven respondents provided the percentage of overall natural gas efficiency program budget spent on marketing activities. Expenditures for marketing range from less than one to 58 percent of overall natural gas efficiency program dollars, and the median spending is 4.7 percent of total efficiency program dollars. Table 7 breaks down program outreach spending into percentage ranges of total program dollars. As shown, more than half the programs spend five percent or less of their efficiency program budget on marketing and outreach.

Table 7

MARKETING DOLLARS AS PERCENTAGE OF OVERALL NATURAL GAS EFFICIENCY PROGRAM BUDGET 67 PROGRAMS	
PERCENTAGE OF PROGRAM BUDGET	NUMBER OF PROGRAMS
1% or less	9
1% > ≤ 5%	30
5% > ≤ 10%	12
10% > ≤ 25%	11
25% > ≤ 50%	4
Greater than 50%	1
TOTAL	67

Nine percent of respondents (8 of 93) indicated that their natural gas efficiency program includes a regulator-approved codes and standards advocacy program that promotes improvements to building efficiency codes and appliance standards. This is performed through studies, drafting guidelines, expert testimony, stakeholder meetings, research, and marketing and compliance improvement activities (such as funding for statewide contractor training on adopted building codes).

Eighteen percent (17 of 94) of respondents indicated that their natural gas efficiency program includes pre-commercial demonstrations of emerging technologies. Of the 17, three stated that their public utility commission requires such demonstrations.

II. NATURAL GAS EFFICIENCY PROGRAM FUNDING AND IMPACTS

This section describes utility funding for natural gas efficiency programs in the U.S. and Canada and the resulting annual energy saving impacts. Program year 2009 expenditures correspond to funding by 108 utilities for programs they or other parties administer. These third-party administrators include nonprofit public benefit organizations and state agencies that run statewide programs. A small part of 2009 expenditures were not finalized and will be subject to true-up. Approved budgets for 2010 represent planned funding for 115 programs (including five launched in 2010). Budget data were collected during spring and summer 2010; therefore, any budgetary changes made after this period—due to newly approved programs or funding cuts—are not reflected in this report. Some dollars reported for 2010 represent carryover of unspent funds from 2009.

Respondents were asked to break down 2009 expenditures and 2010 approved budgets by customer class or segment. Where data were not available by segment, a slight percentage of respondents reported overall spending amounts in the "Other" category. In cases where respondents were unable to break down spending for certain activities (such as evaluation, measurement and verification) into discrete customer segments, they placed all dollar amounts corresponding to this activity under "Other." Also in some cases, respondents were not able to separate low-income program dollars from residential program funds (either overall or for specific activities, such as education and online resources), and a small number of commercial program dollars were combined with residential program funds.

All natural gas efficiency program dollars discussed in this report are sourced from ratepayers; however, some program funds originate from other sources, such as utility shareholders and American Recovery and Reinvestment Act (ARRA) dollars. These non-ratepayer dollars have been excluded from this report, and they account for 0.24 percent of 2009 spending on efficiency program in North America and 0.41 percent of 2010 reported funds. Given that the reporting methodology varies among respondents, expenditure and budget data should be regarded as estimates rather than exact figures.

Natural Gas Efficiency Program Expenditures and Funding

In the U.S. utilities spent nearly $803 million in 2009 on natural gas efficiency programs and plan to spend about $1.1 billion in 2010. Program expenditures approached $870 million in North America in 2009 and are expected to exceed $1.2 billion in 2010 (see Table 8). See Appendix B and C for state and region breakdowns of natural gas efficiency program funding by companies that agreed to release their data.

Table 8

Natural Gas Efficiency Program Expenditures and Budgets by Customer Class[1]

	2009 Expenditures ($ Million) 105 Programs			2010 Approved Budgets ($ Million) 115 Programs (4 Pending)		
Customer Segment	U.S.	Canada	N. America	U.S.	Canada	N. America
Residential	$296.3	$20.1	$316.4	$463.5	$19.0	$482.5
Low-Income	$275.6	$6.8	$282.4	$313.6	$14.9	$328.5
C & I	$170.2	$22.8	$193.1	$278.1	$24.6	$302.7
Other[2]	$60.5	$17.2	$77.6	$88.8	$26.5	$115.3
TOTAL[3]	$802.6	$66.9	$869.6	$1,144.0	$85.0	$1,229.0

[1] Subcategories might not add up exactly to reported totals due to rounding.

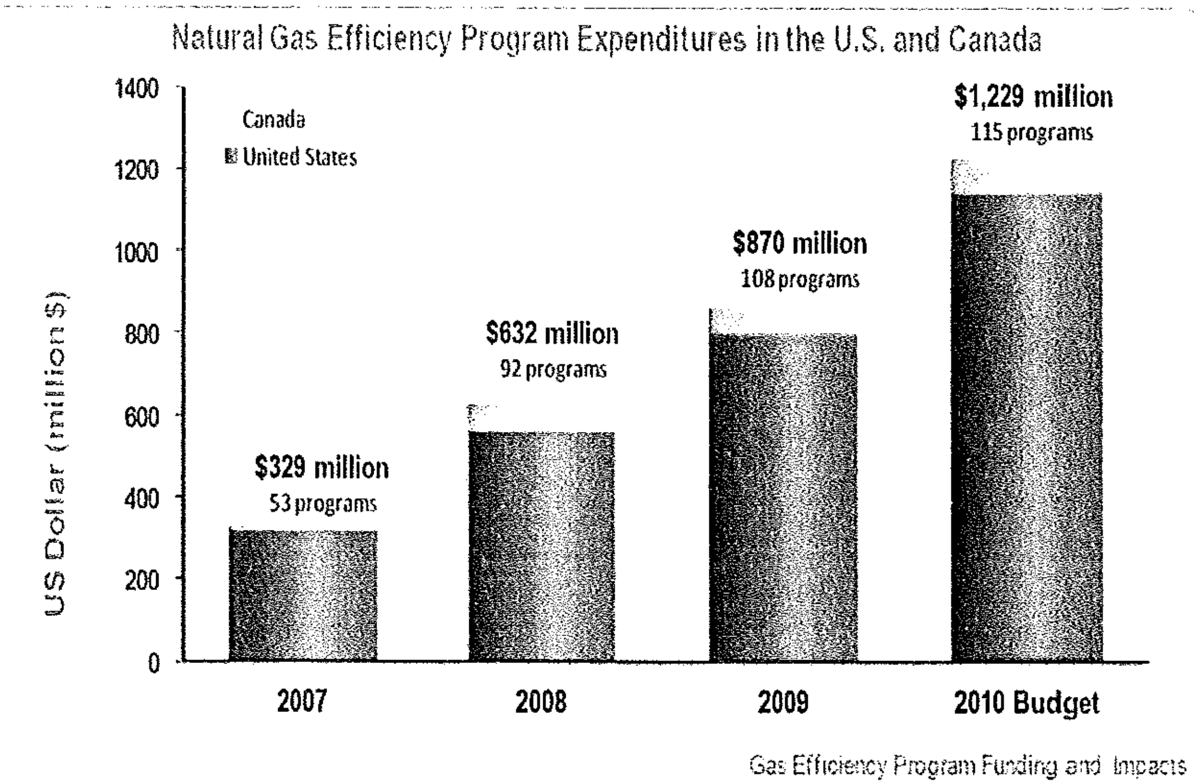
[2] A small percentage of funds in "Other" represent EM&V funds not included in the segment categories.

[3] All currency is reported in U.S. dollars. This report uses the July 8, 2010 exchange rate of 0.9544 USD = 1 CAD.

Program funding in North America increased by 38 percent from 2008 to 2009 and is expected to grow by 41 percent in 2010. In the U.S., program funding grew by 42 percent from 2008 to 2009 and is expected to grow by 43 percent from 2009 to 2010. This comparison is intended for illustrative purposes only, since spending growth cannot be entirely attributed to new and expanded programs but also to differences in survey samples from one year to the next.

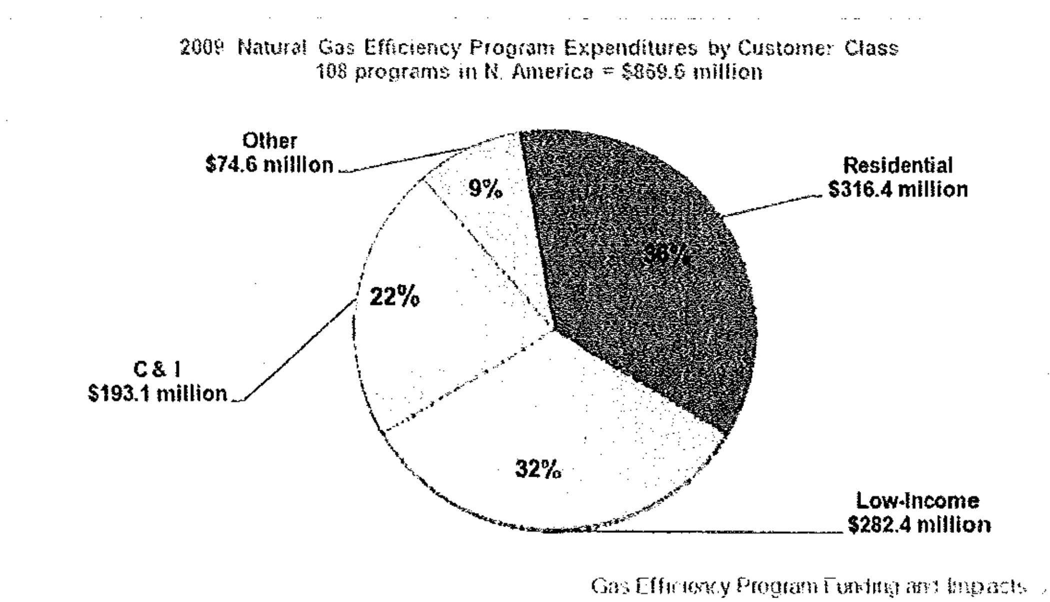
Figure 5 presents natural gas efficiency program funds from 2007 through 2010.

Figure 5



A look at 2009 natural gas efficiency program expenditures across sectors shows that North American utilities apportioned 36 percent of funding for residential programs, 32 percent for low-income, 22 percent for C&I, and nine percent for other program activities (see Figure 6).

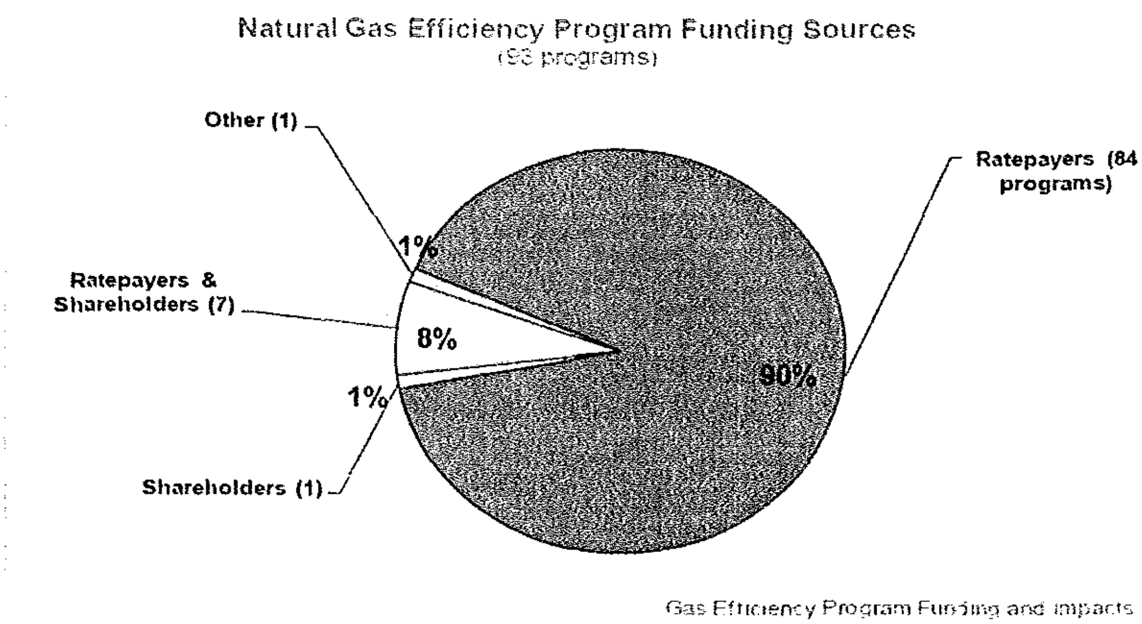
Figure 6



Expenditures that were not include in the segment categories includes labor and administrative costs; market research and transformation; planning and development; pilot programs; marketing and outreach; education campaigns; contact centers; tracking systems; EM&V; codes and standards; emerging technologies; renewable energy; DSM coordination; regulatory filing and state oversight charges; and contractor training.

Figure 7 shows the distribution of natural gas efficiency program funding among sources in 2009. Ninety percent of programs are funded solely by ratepayers (via base rates, system surcharges or special natural gas efficiency tariffs), one percent by shareholders only, eight percent by shareholders and ratepayers, and one percent by other means.

Figure 7



Based on 80 survey responses, utilities disbursed from 0.01 to 9.5 percent of net natural gas distribution revenues (net of gas costs) for natural gas efficiency programs in 2009. The median spending is close to one percent of net distribution revenues. Of the 80 responding companies, half used less than one percent of net distribution revenues for natural gas efficiency programs, 34 used one percent to less than five percent, and six spent five percent or more.

Natural Gas Efficiency Program Savings Impacts

Estimated 2009 annual natural gas savings impacts were reported for roughly 98 programs by customer class. Respondents were requested to report energy savings realized by gas efficiency measures during the 2009 calendar. This includes calendar year savings from natural gas efficiency measures already in place at the beginning of the year as well as incremental savings realized from new measures implemented during the year. A number of respondents (about 10 percent) were limited by the manner in which they track and report energy savings and thus did not provide annualized savings as defined above (with pre-existing measures and participation taken into account) but rather reported only incremental, or first-year, Therm savings.

Data were not available for a number of respondents, either because savings are not tracked or not yet available for 2009. In some of these cases, estimates were provided based on prior year data. While the majority of respondents provided calendar year savings accumulated in 2009, some were able to report only for the most recent program year (with, for example, some program months falling in 2008 and some in 2009). Where data were not available by segment, a slight percentage of respondents reported overall savings in the "Other" category.

Respondents were also asked for net impacts—that is, to exclude free riders, savings due to government mandated codes and standards, reduced usage owed to weather or business cycle fluctuations, and reduced usage because of natural operations of the marketplace (e.g., higher prices). Many respondents report deemed savings—a set calculation of savings per measure, developed pre-installation, with built-in assumptions regarding free ridership and other specifications. About 47 percent of the respondents that reported savings data were able to provide net impacts, and the remainder provided gross savings.

Some respondents were unable to separate low-income program savings from overall residential program savings, while others combined commercial program savings with residential impacts. Still others included savings for multi-family programs with C&I program savings. These combined categories represent a very small percentage of the data. Given that the reporting methodology varied among respondents, natural gas savings data should be regarded as estimates rather than exact figures.

As shown in Table 9, in 2009 U.S. utilities saved nearly 529 million Therm (or 52.9 trillion Btu) through natural gas efficiency programs, thus avoiding 2.8 million metric tons of carbon dioxide emissions (CO_2). Natural gas savings in North America were about 898 million Therm (or 89.8 trillion Btu), the equivalence of 4.7 million metric tons of avoided CO_2 emissions. For a breakdown of savings impacts by region, see Appendix D.

Table 9

2009 Natural Gas Efficiency Program Savings Impacts by Customer Class (Million Therm) - 98 Programs

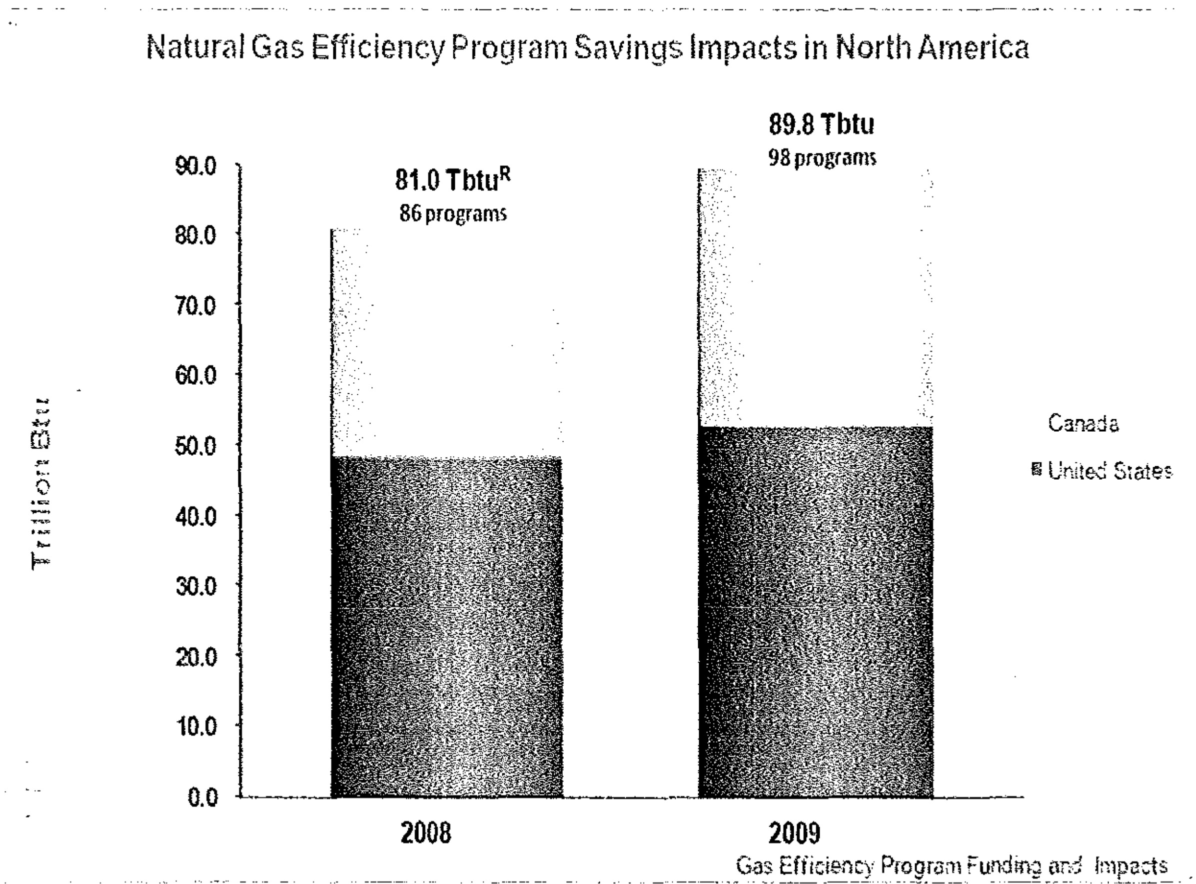
Sector	United States	Canada	N. America
Residential	179.4	84.2	263.6
Low-Income	38.1	4.6	42.7
Commercial & Industrial	288.2	283.7	571.8
Other[1]	23.3	(3.1)	20.2
TOTAL[2]	529.0	369.4	898.4

[1] The negative number represents interactive effects of DSM electric savings.

[2] Subcategories might not add up exactly to reported totals due to rounding.

Natural gas savings from U.S. efficiency programs grew by nine percent in 2009 to 52.9 trillion Btu (from 48.4 trillion Btu in 2008). Figure 8 compares 2009 savings with prior year data and shows that natural gas savings in North America increased eleven percent (from 81.0 trillion Btu in 2008 to 89.8 trillion Btu in 2009)[7]. This comparison is for illustrative purposes, because this growth cannot entirely be attributed to new and expanded programs but also to differences in survey samples from one year to the next.

Figure 8

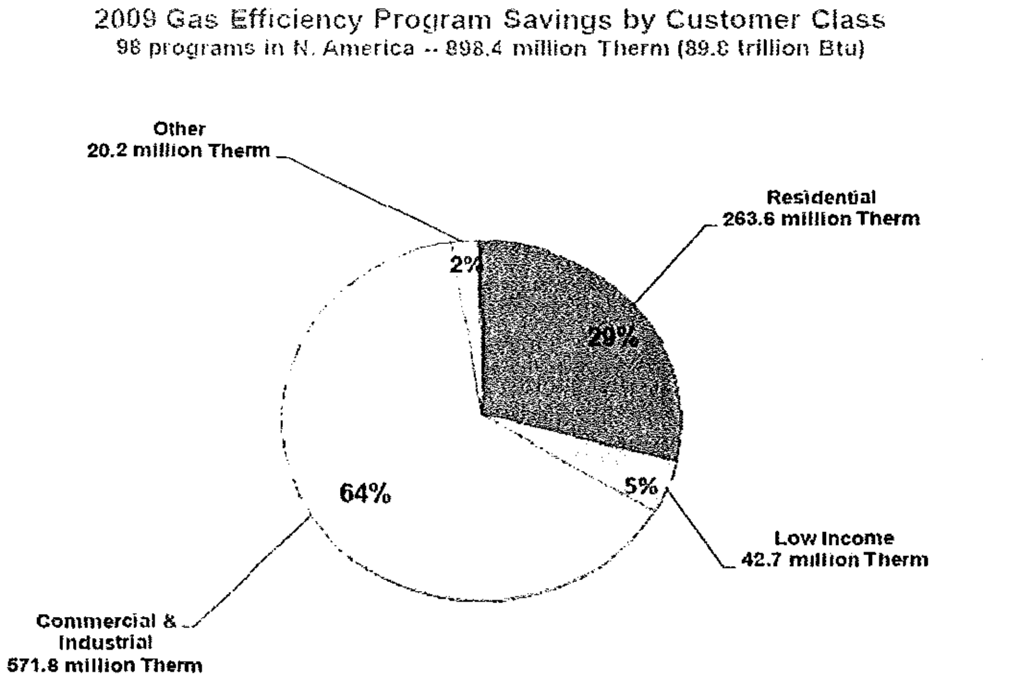


In the United States, residential savings account for 41 percent of overall savings (of which seven percent are from low-income programs), and C&I program savings account for 54 percent. Four percent of U.S. savings is classified as other, representing data not allocable by customer class and including estimated savings for education, general outreach, codes and standards, and pilot programs.

[7] Natural gas efficiency program savings for the 2008 program year have been revised for the U.S. and Canada since this report was last updated in December 2009. A number of companies had provided first year savings for newly installed measures in 2008 rather than annualized savings for all measures that achieved savings during 2008 (whether pre-existing or newly installed). They therefore revised 2008 numbers to meet the specific definition for annualized savings (see page 15), thus provided comparable data for 2008 and 2009. In Canada, annual savings from established natural gas efficiency programs are generally high. This is because of substantial savings opportunities from gas heating programs in this cold climate and the long-term nature of installed measures.

A look across segments at 2009 natural gas efficiency programs in North America shows that 29 percent of savings are attributed to residential programs, 5 percent to low-income activities and 64 percent to C&I programs (see Figure 9). Two percent of North American natural gas savings is classified as "other,"

Figure 9



Gas Efficiency Program Funding and Impacts

In the U.S. annual natural gas savings per efficiency program participant averaged nine percent for residential participants and 7.4 percent overall. Natural gas savings per year averaged 122 Therm per U.S. customer overall and 69 Therm per residential customer, which translates to average cost savings per residential customer of $83 on annual energy bills[8].

[8] Natural gas efficiency program data for both participant counts and annual savings were available for 69 programs. Average cost savings were derived from survey data for the 69 programs, 2008 Energy Information Administration (EIA) consumption data per company by end use, and EIA average natural gas end-use price.

III. Natural Gas Efficiency Program Planning and Evaluation

Survey respondents were asked to describe their approach to natural gas efficiency program planning, measurement and evaluation. Forty-six percent of respondents (42 of 91) completed a full scale or smaller market assessment (or some form of efficiency potential, baseline, or feasibility study) before implementing their natural gas efficiency programs.

Seventy-seven percent of respondents (72 of 93 active programs) include an evaluation, measurement and verification (EM&V) component in their natural gas efficiency program. However, not all were able to report expenditures and budget figures, either because 1) these are not separated from other administrative budgets; 2) evaluations and reports are completed in house and incremental costs are not itemized; 3) program evaluations are not due in 2009 or 2010; or 4) contract negotiations with third-party EM&V vendors are ongoing.

Expenditures for 2009 EM&V were obtained for 46 of the 72 active programs that have EM&V activities, and 2010 EM&V budgets were provided for 56 active and two planned programs. EM&V expenditures surpassed $12 million in the U.S. in 2009 and are estimated to approach $31 million in 2010—a 150 percent increase. In North America, 2009 EMV spending approached $14 million and is expected to exceed $32 million in 2010 (see Table 10).

Table 10

Evaluation Measurement & Verification Expenditures and Budgets		
Region	2009 Expenditures ($) 46 Programs	2010 Budget ($) 58 Programs
United States	$ 12,371,305	$ 30,976,904
Canada	$ 1,340,707	$ 1,651,518
N. America	$ 13,712,012	$ 32,628,422

In 90 percent of programs (79 of 88), the utility is responsible for conducting the impact evaluation, and in the remaining 10 percent, the evaluation is the regulatory commission's purview. When the utility is the responsible party, the evaluation is conducted by a consultant for 61 percent of programs (48 of 79), by in-house staff for 35 percent (28 of 79), and by both internal staff and outside agent for four percent (3 of 79). In the latter case, in-house staff may oversee and coordinate multiple independent evaluation consultants undertaking impact evaluations and process assessments.

Eighty-seven of 93 survey respondents (94 percent) indicated that they are required to report natural gas efficiency program impacts at regular intervals to their regulator or other authority. Others are asked for informal evaluations by their regulators instead of a formal impacts report. When asked how often evaluators must submit a program report, respondents selected one or more timeframes, depending on the type of evaluation and intended recipient.

Table 11 shows the required reporting cycles for program evaluators. Eighty-three percent of respondents are required to submit an annual report. Other than monthly, quarterly and annually, reporting frequencies include semi-annual, once in three years, in five years and in six years.

Table 11

EE Program Reporting Frequency 87 survey responses with one or more reporting cycles	
Monthly	17
Quarterly	25
Annually	72
All of the above	10
Other	11

Thirty-six percent of respondents are required to report net savings impacts, 49 percent report gross savings and 15 percent include both in their report. Fifty-five of 93 respondents indicated that their organization has quantitative program savings goals. These goals may be set by the regulatory commission, oversight board, state legislature, natural gas utility, a consultant, or advisory council. Often they are negotiated among utility, regulator and stakeholders through a regulatory process. Most often the Therm savings goals is set for one calendar or program year; however, in some cases the goal is for a range of years.

When assessing annual energy savings derived from direct impact natural gas efficiency programs, 42 percent of respondents (38 of 90) determine savings at the individual program level, four percent (4 of 90) at the overall portfolio level, and 52 percent (47 of 90) at both levels. Eighteen percent of respondents (17 of 92) determine energy savings achieved from indirect impact programs (such as conservation and efficiency education), and one other is considering this approach.

Of the 82 natural gas efficiency programs for which cost effectiveness is evaluated, 32 percent (26 of 82) are assessed only at the individual program level, 11 percent (or 9 programs) for the overall portfolio, and 1 percent (or 1 program) by customer segment. Forty percent (33 programs) determine cost effectiveness for both individual program and the entire portfolio, and 16 percent (13 programs) conduct tests at all three levels. In several programs, cost-effectiveness tests are conducted at the measure level, including custom measures. In another case, the investor-owned utilities in the state are required to conduct various cost-benefit tests at multiple levels, and the small and multi-jurisdictional utilities are allowed to mimic their program savings.

Table 12 shows how respondents answered when asked to describe all tests used to determine cost-effectiveness. Total Resource Cost testing was used by 76 percent of respondents (62 of 82). Fifteen percent (or 12 respondents) reported using all five tests.

Table 12

Tests Used to Determine Natural Gas Efficiency Program Cost-Effectiveness[9] 82 responses with one or more test	
Participant Test (PCT) Calculates quantifiable costs (e.g., out of pocket expenses of participating in program) and benefits (e.g., reduction in utility bill, rebate payments, tax credits) to participating customers	42
Ratepayer Impact Measure (RIM) Applies only to utility programs—measuring impact on all consumer bills/rates because of changes in utility revenues and operating costs due to program implementation	38
Utility Cost Test (UCT) Narrower version of TRC—excluding participant costs and measuring net costs incurred by program administrator (e.g., customer rebates and other financial incentives) at the utility (UCT applies) or at other organization (PAC applies)	51
Total Resource Cost (TRC) Measures net program costs—including both participants' and utility's costs (e.g., equipment and installation, operation and maintenance and other related costs of participant and utility) and benefits (e.g., avoided supply costs, natural gas delivery cost reductions, tax credits)	62
Societal Test (SOC) Broader version of TRC adopting a societal perspective—measuring not only participants' and utility's costs but also externality cost and benefits (e.g., environmental impacts)	29

Sixteen percent of respondents (14 of 90) indicated that a reduction of greenhouse gas (GHG) or carbon emissions is a performance target for their natural gas efficiency program. Of the 15, nine respondents (or ten percent) track such reductions. Five others do not consider emissions reduction a performance measure, yet they track it and, in some cases, report their findings. Some opt to do so as a means to determine the cost-effectiveness of their program. Two others that do not track emission savings reported that they do contemplate them when selecting cost effective measures.

When asked how they calculate energy efficiency gains for specific programs or measures, respondents indicated that they use source-to-site energy measurement in 14 percent of programs (12 of 86), and site-only measurement in 86 percent of programs.[10] Thirty-four percent of respondents (29 of 86) use a given metric because they are required (mostly through regulatory precedent or filing requirement but also by legislation), 47 percent because of available resources, and 19 percent for other or unspecified reasons. Other reasons given for their current approach are ease of use; common practice for utility-sponsored programs; consistent with other utilities in same jurisdiction; limited to deemed savings computations developed by regulator; based on energy Star standards; existing practice for statewide programs; considered as a true measurement of efficiency; and not approved by regulator.

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[9] For a thorough description of each cost-effectiveness test, see Appendix C-4 in *Model Energy Efficiency Program Impact Evaluation Guide*, A Resource of the National Action Plan for Energy Efficiency, November 2007, www.epa.gov/cleanenergy/documents/evaluation_guide.pdf

[10] Source energy—also known as full fuel cycle analysis—is a more accurate measurement of efficiency. Site energy analysis accounts for energy used or consumed only by the end-user at the usage site. On the other hand, a full fuel cycle analysis takes into account not only onsite energy consumption but also consumption and losses during the production, generation, transmission and distribution cycles. This allows for a realistic comparison of relative efficiency among different technologies, especially when comparing the efficiency of natural gas applications from source to site with that of other fuels.

IV. Natural Gas Efficiency Regulatory Requirements and Cost Recovery Treatment

This section describes some of the regulatory and legal requirements and allowances that surround natural gas efficiency programs in the U.S., including direct program cost recovery, lost revenue treatment and financial incentives for well-performing programs. Data were provided for 94 natural gas efficiency programs (including two in Canada), although not all respondents answered all questions.

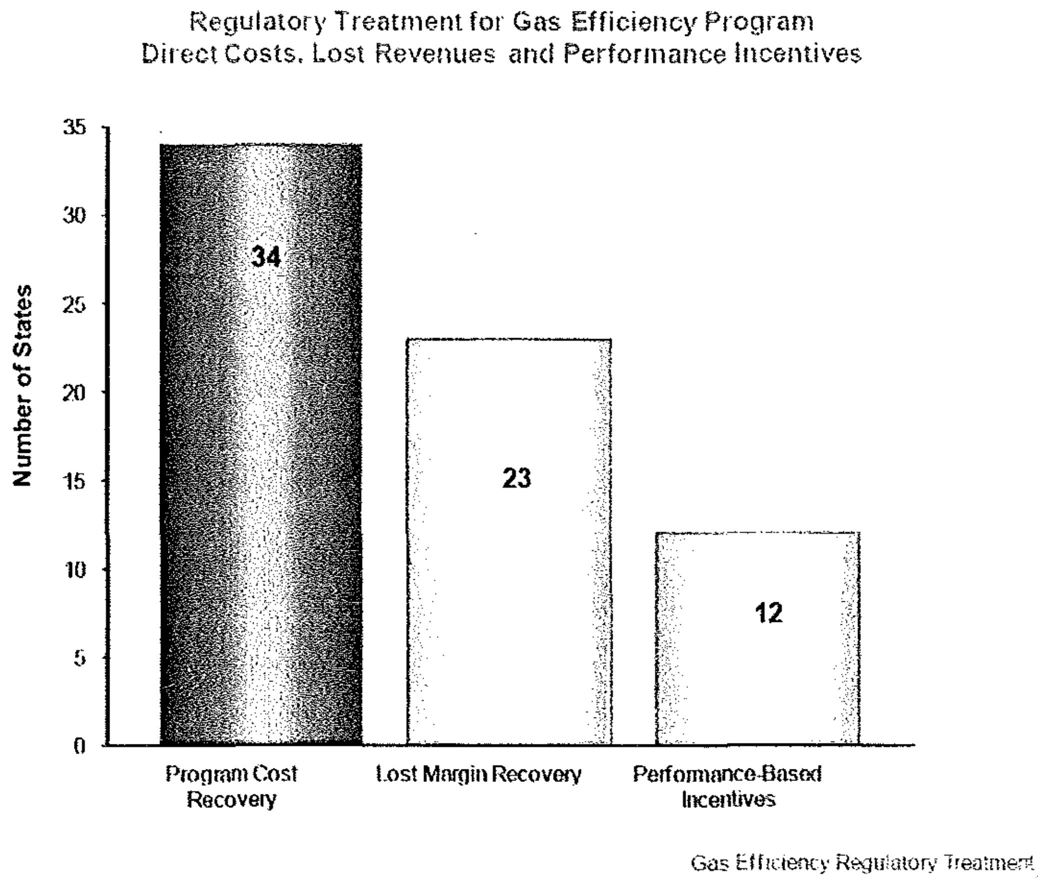
According to survey responses, market studies were conducted in 22 states and Ontario to assess the economic and efficiency potential of natural gas efficiency program implementation. Twenty-eight states and Ontario require utilities to support natural gas efficiency programs with either ratepayer or shareholder funds—by way of regulatory ruling (eight states and Canada), legislative act (seven states) or both rule and bill (in 13 states). The goals that drive this efficiency program funding requirement are energy conservation and savings (66 respondents in 26 states and Canada); customer dollar savings (29 in 17 states and Canada); greenhouse gas emission reductions (28 in 13 states and Canada); and job creation (17 in ten states). Eighteen states and Ontario have set more than one goal, of which eight pursue all four goals. In five states, other goals have been stipulated, such as least cost planning, expenditure levels, or required low-income program implementation as part of a rate case settlement or approval for revenue decoupling.

Only one state in which GHG or carbon emissions reduction is a measureable goal allows a return on investment for carbon offset programs. In two other states, approval is pending for earning credit for such programs (either through cost recovery or investment returns). Individually, five of 83 respondents successfully sought regulatory approval for cost recovery or earnings on projects for which GHG emissions reduction is a primary goal. These programs include renewable energy certificate purchase programs and carbon offset purchase programs, supporting wind farms and biogas generating plants. Three respondents were denied cost recovery or earnings credit for their carbon offset programs, and seven others are exploring similar options.

Twenty-five states and Canada require utilities to fund conservation and efficiency programs for low-income customers. According to 36 respondents in 22 states and Canada, income-qualified programs are subject to a cost-effectiveness "litmus test" that determines program sustainability and/or eligibility for cost recovery. Seventy-two percent of respondents (67 of 93) said that their regulator requires them to use a specific cost-benefit test (such as ones listed in Table 12) as a performance measure. This calculation is based on net savings for 61 percent of respondents (41 of 67), on gross savings for 37 percent (or 25 respondents) and on both net and gross impacts for two percent (one of 67).

Respondents identified, besides Canada, 34 states that allow recovery of natural gas efficiency program costs, 23 that allow lost margin recovery owed to implementing efficiency programs, and twelve that offer utilities financial incentives for well-performing natural gas efficiency programs (see Figure 10).

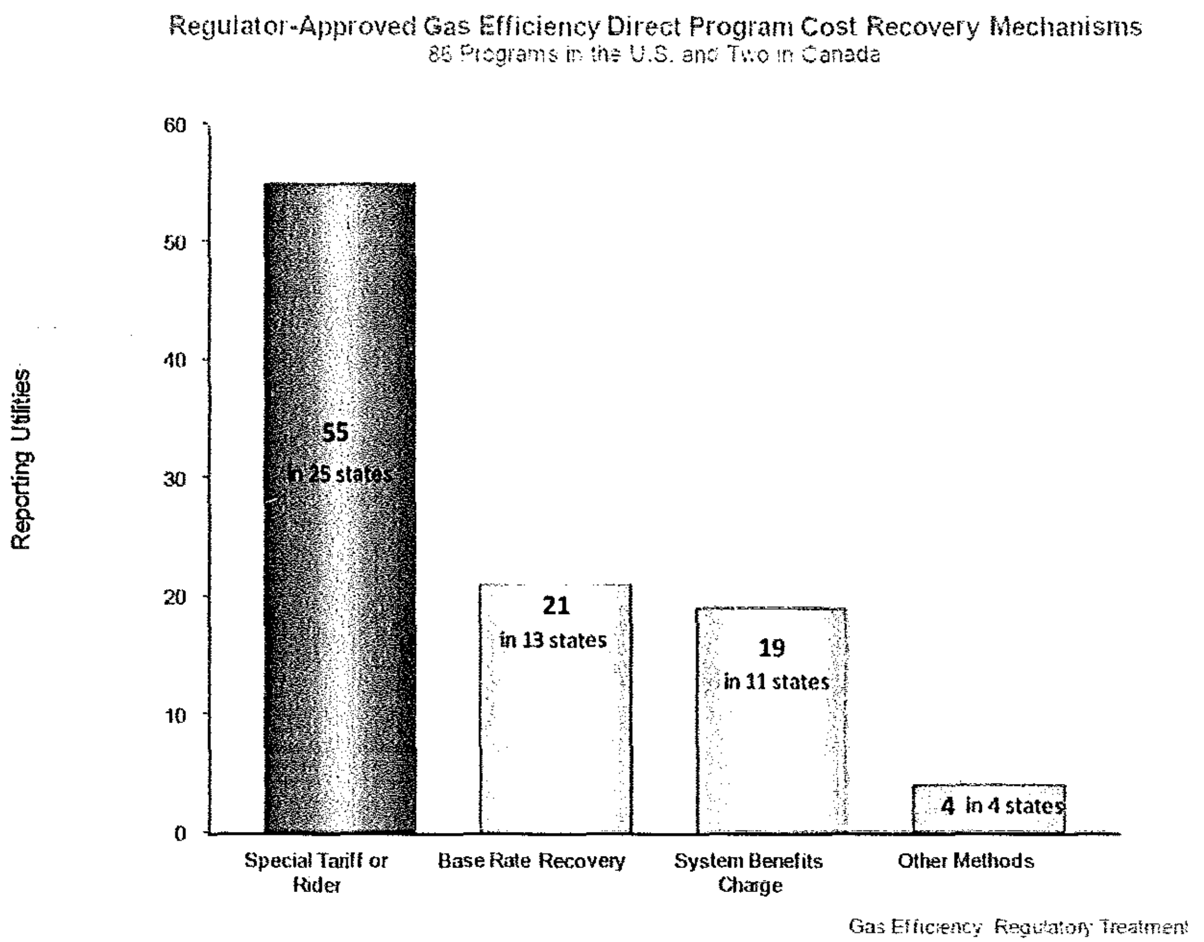
Figure 10



Eighty-six natural gas efficiency programs are administered in the 34 states identified as having assured recovery of natural gas efficiency program costs (e.g., rebates and administrative costs). Program cost recovery is pending regulatory approval in one other state. Only four respondents reported an inability to recover natural gas efficiency program costs.

Utilities use one or more mechanism to recover costs as follows: 55 companies in 25 states and one in Canada use a special efficiency or conservation tariff rider; 21 in 13 states and one in Canada embed natural gas efficiency program costs in base rates; and 19 in eleven states apply a mandated system benefits (or public goods) surcharge on customer bills (see Figure 11). Four in four states use other mechanisms in the form of other ratepayer surcharges, such a Regional Greenhouse Gas Initiative Recovery Charge, Conservation Adjustment Mechanism, and a charge on electric bills to recover low-income weatherization program costs).

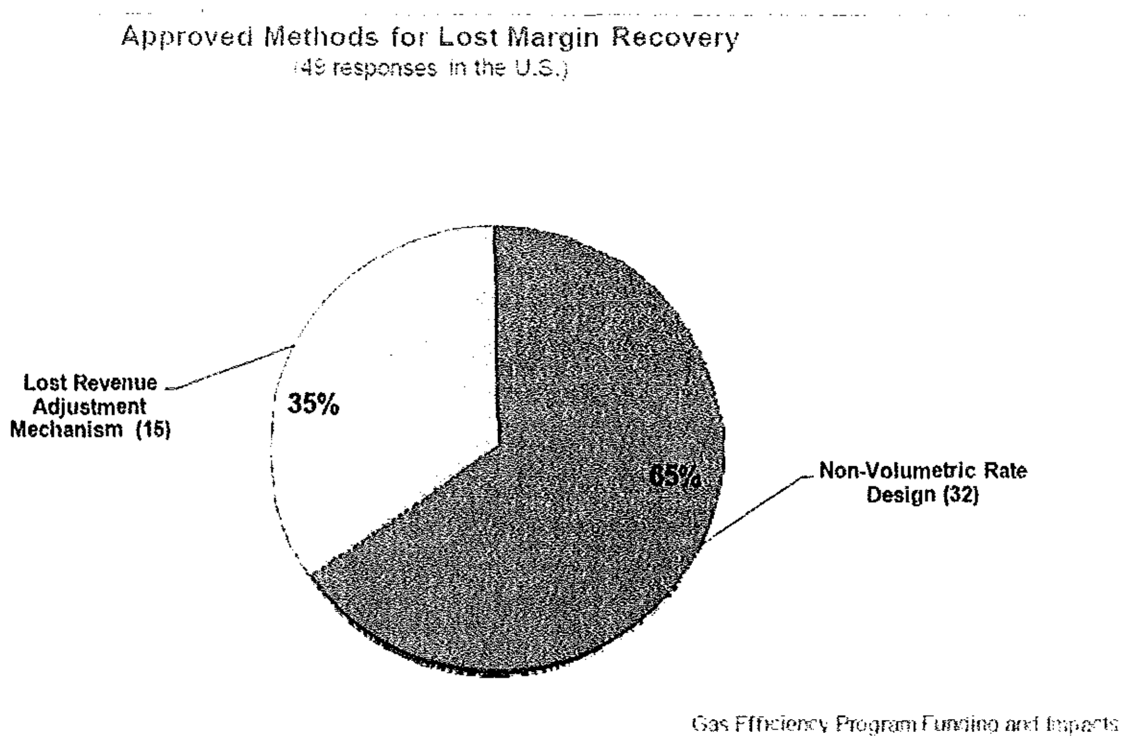
Figure 11



Forty-nine natural gas efficiency programs are implemented in the 23 states identified in the survey as having approved recovery of lost revenues and margins that result from natural gas efficiency program implementation. Lost margin recovery provisions are pending for seven utilities in two states. Thirty-four respondents reported that they are not allowed to recover lost margins owed to implementing natural gas efficiency programs.

As shown in figure 12, of the 49 U.S. utilities allowed recovery of lost margins, 32 in 15 states have a non-volumetric rate design and 15 in 13 states use a lost revenue adjustment mechanism (an after-the-fact surcharge or conservation rate adjustment mechanism applied specifically to efficiency programs).

Figure 12

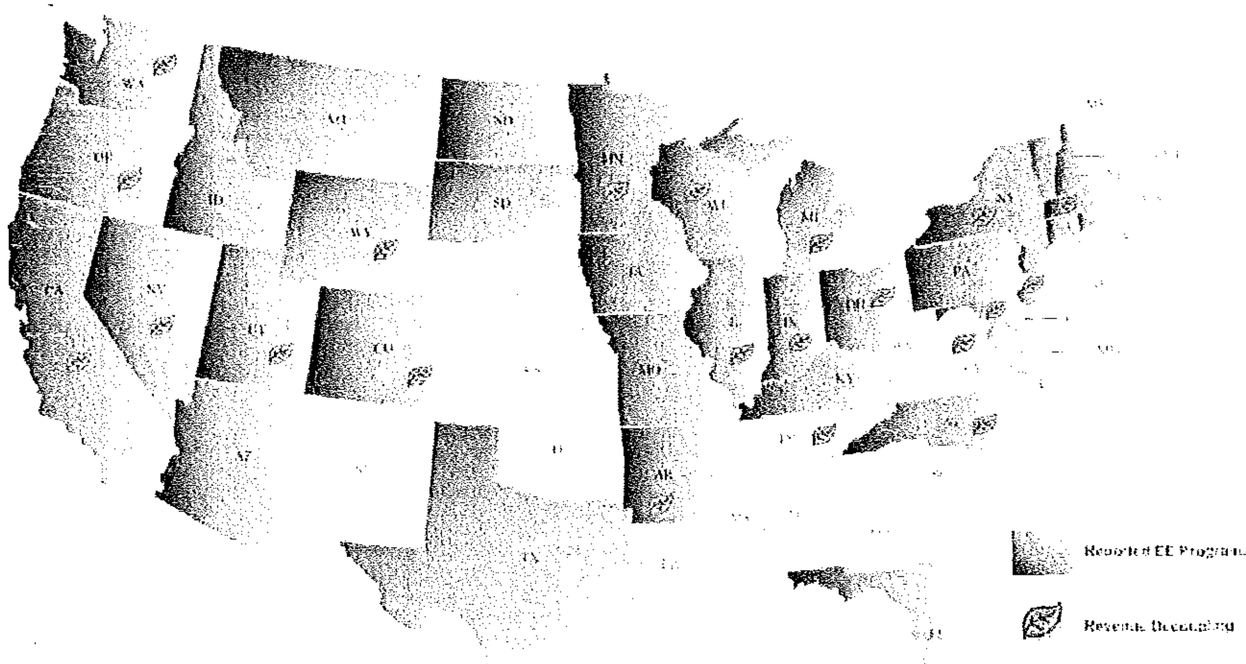


Of the 32 respondents in the 15 states with non-volumetric rate designs, 17 (or 53 percent) have full revenue decoupling, three have partial revenue decoupling, nine have revenue decoupling with restrictions, and three have a straight fixed variable (SFV) rate design. For those with partial revenue decoupling, the recovered lost margins are either limited to a specific percentage of revenues or must be equal to the achieved natural gas cost saving. Restrictions on revenue decoupling include 1) limiting margin recovery to a pre-determined return on equity, 2) applying a limited billing determinant adjustment that offsets customer or volumes losses in the residential and small business class with gains in large business customer or volumes; 3) excluding industrial customers and weather adjustments; 4) basing adjustments on actual usage per pre-existing customer and DSM triggers; 5) applying an earnings and energy savings test; and 7) basing margin-per-customer rate adjustment on fixed therm savings measures for each energy efficiency program and stipulated rates for each service classification.

As seen in Figure 13, natural gas efficiency programs are implemented in nearly all states that allow decoupling of natural gas utility revenues.

Figure 13

States with Natural Gas Efficiency Programs and Revenue Decoupling – 2009 Year



Source: 2010 Natural Gas Efficiency Programs Survey and Natural Gas Rate Round-Up – Update on Regulatory Approaches to Promoting Energy Efficiency, May 2009

Thirty programs are run in the twelve states identified as having regulator-approved financial incentives for implementing natural gas efficiency programs—including performance targets, rate of return incentives, and shared savings. Of the 30 respondents, 16 have a performance target incentive mechanism that bases financial rewards on meeting or exceeding specific program goals. Performance targets may include prog7ram-specific Therm saving thresholds; percent achievement beyond the mandated energy savings minimum (ranging from 115% to 125% of target); compliance with least cost procurement provisions; sector-level total resource cost effectiveness ratios; and explicit net economic benefits to consumers. The financial bonus may be based on a percentage of before-tax design level program expenditures; capped at specific dollar amounts; a percentage of program savings and metrics; or a percentage of the net economic benefits resulting from the DSM plan over the period under review.

Nine respondents have a shared saving mechanism that gives them a share of program savings, and three have a combination of performance targets and shared savings. Based on twelve responses, utilities are eligible to share between four and 30 percent of customer savings, and the median share is 20 percent of customer savings.

Two respondents have rate of return incentives, allowing them to make a profit on their natural gas efficiency investments equivalent to their authorized rate of return for utility supply-side investments. One respondent is awaiting regulatory approval for energy efficiency-related utility performance incentives.

Sixteen percent of U.S. respondents (14 of 86) reported that their regulator-approved natural gas efficiency program encourages fuel switching through financial incentives (e.g., rebates, loans and other benefits) to customers who install natural gas equipment in new homes, convert to natural gas from other fuels, or replace old equipment with new higher-efficiency natural gas equipment.

Appendix A summarizes natural gas efficiency program practices and regulatory requirements by state and for Canada. This includes market assessment studies, mandated utility funding for natural gas efficiency programs, requirements for low-income residential programs, approved recovery for direct program costs and lost margins, utility performance incentives, fuel switching and source-to-site energy measurement[11].

[11] For a more thorough explanation of regulatory treatment that supports energy efficiency programs, including specific program examples, see *Natural Gas Rate Round-Up — A Periodic Update on Rate Designs: Update on Regulatory Approaches to Promoting Energy Efficiency, AGA: May 2009.* Also visit AGA's *Rates & Regulatory Policy* web page for periodic updates on innovative rate designs: http://www.aga.org/OUR-ISSUES/RATESREGULATORYISSUES/RATESREGPOLICY/Pages/default.aspx.

Appendix A

V. Thoughts and Comments

Program administrators were asked to share their experiences with implementing natural gas efficiency programs. The following is an anecdotal account based on respondent observations regarding lessons learned, program delivery barriers, market penetration, most successful attributes and program innovation.

Delivery Barriers and Lessons Learned

The economic downturn, particularly in hard hit areas, continued to pose a challenge for many program administrators during 2009. This prevented customers with limited resources from taking advantage of appliance replacement rebates. Also businesses elected to extend the life of their existing equipment rather than invest in new high efficiency natural gas appliances. One remedy was to raise rebate levels to strengthen participation. In other markets, on the other hand, the general state of the economy and media coverage of gas prices spurred customers to invest in higher efficiency measures that would save them money in the long term.

In mature markets, hurdles to program delivery generate from competing energy efficiency service providers. Also with the low-hanging efficiency targets already garnered, the challenge for program implementers in such markets is to develop innovative efficiency programs while maintaining cost-effectiveness. For them, the need for newer energy efficiency technologies is more pressing and may help stimulate these saturated markets. Automated rebate systems also help streamline administrative processes for large programs, and monitoring and tracking systems provide program administrators with essential data for evaluating, validating and sustaining their programs.

In newer programs, among the most cost-effective measures are programmable thermostats and conservation education. Rehab projects and weatherization are other areas that provide greater savings potential, particularly with high-use, low-income residential customers. However, to optimize savings, it is necessary to set adequate levels of funding for materials per customer and an appropriate poverty qualification threshold.

When starting new programs, it is important to build in a realistic timeframe for program ramp up (from program launch to customer awareness and participation), taking into account the many factors that can impact this phase. Establishing early a robust marketing budget is a key factor: Well-timed, simple, and targeted advertising helps shorten the time needed to build up participation levels. Direct, regular outreach to customers is also a quick way to ensure that they are properly educated about program availability and offerings. Programs that have partnered with other utilities and organizations—including community-based agencies—have found success in reaching a wider audience and encouraging behavioral change by customizing pro-conservation messages for specific geographic regions and different consumer cultures.

Demand for residential high-efficiency space heating programs is high in many areas; however, certain factors can determine the outcome. Essential for these contractor-driven programs are networks of trained contractors that are incentivized and aware of program offerings and incentives and can carry out quality installations. As one respondent has stated, "contractors are the most influential channel in selling high-efficiency equipment and providing information on rebates." Thus it is generally agreed that a necessary component of successful program delivery is a strong trade alliance (with HVAC contractors, energy auditors, plumbers, mechanical contractors, foodservice dealers and so on). Regular contact with these trade allies not only helps with program marketing but also improves the likelihood that high-efficiency equipment, such as water heaters, will be stocked rather than special ordered. In some markets, poor inventories are a common barrier.

Commercial programs are often more difficult to implement because they require even more targeted marketing and a longer ramp up timeframe, although this market is showing promising results in many regions. The small multi-family market (2-8 units) was cited as particularly hard to reach, necessitating several customer contact points to achieve overall therm savings. One program addressed this challenge by adding air sealing as a measure to encourage greater participation and data analysis to identify higher energy users.

Market Penetration

Respondents were asked to specify the degree by which customers recognized and took advantage of natural gas efficiency products and services. This varied by program age, customer segment and program type. Based on 17 of 43 responses, the market penetration for natural gas efficiency programs ranged from less than one to 70 percent in 2009 (calculated in most cases as the ratio of participants to total eligible customers, with the numerator representing the number of enrollments, submitted rebates or subscriptions to online tools). However, looking only at the ratio of participating customers to total eligible customers in order to evaluate program growth generally yields a relatively small percentage.

The median market penetration rate was three percent. Five programs had a participation rate of less than one percent; four had from one to less than five percent; four achieved from five to less than 15 percent; and four reached at least 15 percent of the potential market.

Other respondents provided qualitative or anecdotal answers, ranging from low participation to rapidly increasing. The low ratings were generally for new programs. Others reported strong and rapidly growing participation, while others seem to have hit a plateau. Some of the positive ratings were based on market surveys indicating increased customer awareness resulting in behavioral change, incorporating weather stripping and equipment replacements. Others were based on independent evaluations using statistical analysis of use per customer during the program implementation period. Some respondents were unsure about market penetration in 2009, either because programs were either too new or because data were not available.

Most Successful Attributes

When asked about their most successful program attributes, respondents focused on specific implementation approaches, individual program components and program results. Here is a listing of the most successful attributes of surveyed programs, beginning with the most cited aspects:

Partnerships with Other Stakeholders: Strong trade alliances are fostered in many programs through outreach, education, incentives, training, and shared goals. Many find that contractors, when educated about natural gas efficiency and its benefits to their businesses, are the most effective resource to inform and persuade customers to take advantage of rebate offers.

Many programs have benefited from joining forces with other utilities, in many instances combining or matching natural gas, electric and water saving measures, thus managing to reduce administrative costs and improve process efficiency, while benefiting customers by offering comprehensive services and enhanced financial incentives. Also successful are multi-utility collaboratives that offer consistent market transformation programs across jurisdictions (e.g., GasNetworks collaborative in MA, NH and RI).

Involvement in community-level grassroots conservation efforts has also been constructive, and particularly productive are coalitions with community action agencies that deliver home heating assistance and weatherization services to low-income households. Such ties help to leverage utility low-income energy efficiency program dollars with federal low-income heating assistance program (LIHEAP) funds as well as utility customer assistance program funds. This presents a win-win for customers and utility as it helps minimize write offs of customer payment arrears and thus reduces uncollectible expenses.

Low-Income Usage Programs: As just mentioned, low-income weatherization programs provide many economic and societal benefits, including customer comfort, safety, and cost savings for both the utility and its customer base. For many programs, the low-income weatherization component is the most successful in achieving high energy savings and cost-effectiveness. Another way of coordinating among programs is when higher usage customers are identified via the customer assistance program and those most in need are provided with furnace repairs or replacements.

Commercial and Residential Rebates and Incentives: Without rebates and other incentives such as fixed or low interest financing, many customers would be reluctant to move forward with energy efficiency measures, particularly in this economic climate. Many programs reported a steady growth in residential high-efficiency equipment rebate programs. In some cases, enrollments doubled in 2009 from prior year (e.g. Energy Star Home programs). In other newly launched programs, the level of interest in the residential HVAC replacement program was not well-anticipated by program administrators, and some programs even exceeded their targets.

Residential and Commercial Audits and Customized Retrofits of Large Facilities: Home and business energy audits provide an educational opportunity for customers to learn about energy efficiency, improved natural gas efficiency measures, and cost savings through lower bills. Many programs offer free or low cost energy audits to encourage a whole house approach to energy efficiency. Audit information gives business customers, for example, the opportunity to create an energy plan and seek approval to initiate energy efficiency projects. It was reported that commercial customers regularly implement a large percentage of audit recommendations, and others credited small business outreach programs for improving market penetration.

Other Success Factors: Other elements that are critical to the success of natural gas efficiency programs include expedited program startup; regulatory support via approved cost and lost margin recovery and performance incentives; a renewed ability to market the natural gas advantage; multi-media marketing, including web-based applications; simpler advertising messages via brochures and TV/radio ads; comprehensive portfolios accessible to all segments in the customer base; ongoing customer and vendor communications; customer-friendly programs with a simple rebate process; commercial shared savings programs that alleviate pressure on businesses for up-front capital for natural gas efficiency technologies; hiring, training and using in-house Building Performance Institute (BPI) certified home energy auditors; low cost programs with high energy and cost savings; leveraging dollar savings for new and expanded programs; and an overall commitment to program growth and adaptability.

Successful Programs and Products: Specific products and activities were mentioned as most successful within program offerings. These include a student education program administered by a third party that proved to be very cost-effective; a fuel conversion program from propane to natural gas; residential whole house retrofit programs; multi-family direct install program; custom commercial programs; outreach through multi-media platforms (including web-based tools); ability to leverage trade allies within service franchise; residential equipment replacement program; and customer and vendor communications.

Most Innovative Features

Respondents were asked to share the most innovative features of their natural gas efficiency program. Many of the most successful attributes discussed above were highlighted as the most innovative of these programs. These include strategic partnerships, a whole home or project approach to efficiency, targeted marketing and education campaigns, and new technologies. Specific program components were also featured in the comments submitted for 41 efficiency portfolios. Of course, one feature or component considered innovative in one program might be considered standard in another more mature program.

Strategic Partnerships – Various collaborations were touted as both innovative and successful, including those between two neighboring utilities (e.g., gas, electric and water), multi-utility collaboratives, and strategic partnerships with business that involve program design and delivery and with non-energy related institutions that are interested in promoting energy efficiency green products. Two examples of this success include a joint effort among four natural gas utilities to build a DSM program that saved a considerable amount of money compared to building separate programs. These savings enabled them to pass along higher rebate incentives to their customers.

Another example is the GasNetworks collaborative of several LDCs across three states. Many utilities also collaborate with a competing local electric utility to deliver both natural gas and electric conservation and energy efficiency measures. An example of this is a joint High Efficiency Furnace with Electronically Commutated Motor (ECM) program.

Energy Surveys and a Whole House or Project Approach to Efficiency – Home audits, particularly when coupled with a comprehensive approach to efficiency, yield very favorable results, according to survey respondents. Several programs reported a whole project or portfolio approach to efficiency and a comprehensive assessment of measures for cost-effectiveness. Some programs require a home energy audit to identify opportunities in the shell of the home. Others, after the diagnostic stage, follow-up with customers take extra seal-up steps, gaining their permission to share contact information with BPI-accredited contractors who can provide Tier III seal-ups. Another program links significant financial furnace replacement rebates with prerequisite free energy audits, again with the goal of shifting customers to a whole house approach. Other programs provide larger incentives to higher use residential customers to help them achieve the type of savings traditionally seen in low-income customer weatherization programs. Still others subsidize a portion of the recommended measures, including insulation and air duct sealing.

Targeted Marketing and Education – Many program administrators find conservation education, outreach and targeted marketing to be the most cost-effective tools to achieving energy savings. Some programs have comprehensive school education programs. Others target customers directly via 1) natural gas usage letters that educate customers on ways to conserve energy and lower utility bills; 2) online tools (e.g., My Energy Analyzer); and 3) complimentary energy efficiency kits, some of which are customized for particular markets. Some use the local media to distribute energy efficiency information, while others target trade allies with dealer spiffs incenting them to promote natural gas efficient appliances. Here are a few other examples of successful, innovative approaches to deliver pro-conservation messages to customers:

- Customer Take Control of Your Natural Gas Bill dashboard feature. This program enables customers to go on-line to determine the cause of natural gas bill increases or decreases. Customers can easily navigate to statewide programs to learn more about energy efficiency programs.
- Strategic account managers proactively work with customers on new energy-efficient improvements (e.g., HVAC, appliances and shell measures) to reduce natural gas consumption.
- An advertising campaign to raise awareness and encourage rebate submissions tells customers "You might have $350 hidden in your home." The goal is to encourage new submissions and find customers who had installed space or water heaters during the program year but had not submitted their rebate application.

New Technologies – Many program administrators identified new natural gas efficiency technologies as key to growing their programs. A few have been able to incorporate research and development of new and alternative technologies into their energy efficiency programs. A few others are allowed to pilot new technologies within their space and water heating programs, which if successful, will enable them to transfer many custom or innovative features over to mainstream programs (e.g., tankless water heaters).

Other Innovative Features – Other program features that were identified as innovative include the following:

- Annual balancing adjustment to true up program
- Air sealing for 2-8 family units as a new outreach tool to help improve market penetration with this hard to reach customer
- Custom prescriptive program for commercial customers that do not qualify for energy efficiency projects in the regular commercial prescriptive program, offering them up to $25,000 for a qualifying project

- Financing for residential retrofit and equipment replacement customers at zero or very low interest rates; also basing loan and repayment amounts on customer rates and energy bills
- Large scale, pilot residential Home Energy Reports program—provided to customers via the web and by mail—which combines advanced analytics to evaluate customers' energy usage patterns with proven behavioral science techniques to motivate action. Each report compares individual monthly energy use with similar households within the same geographic location and recommends household-specific energy efficiency tips.
- Leveraging rate payer funds with ARRA funds through community action agencies to provide more effective and complete weatherization services to more homes
- Low-income multi-family program that is both cost-effective and comprehensive (achieves about 30% savings per unit)
- New technology embraced, adding smart low-flow showerheads as new program measures. This showerhead has a low flow rate and a thermal actuated valve that slows the hot water to a trickle until the bypass valve is pulled by the user. This reduces the amount of hot water that goes down the drain, saving both natural gas and water.
- Novel administrative structure: 80 percent of portfolio implemented by women and minority-owned firms and local nonprofit organizations
- Pre-rinse spray valve direct install program for small commercial customers, providing Therm savings and allowing survey intake on other natural gas appliances at the customer's facility
- Programs such as fuel conversion from propane to natural gas; home hearth and space heating; and multi-family direct install program
- Other programs such as appliance recycling and customized performance tracking systems
- Public utility commission leadership in state low-income energy efficiency program—providing a wealth of subsidies and programs to low income customers
- Shared savings program for commercial and industrial customers to finance energy-efficient improvements
- Umbrella approach to design, implementation and marketing of programs and efficiency information.

State Natural Gas Efficiency Program Provisions and Practices

STATE	Active EE Program(s)	EE Market Assessment Studies	Utility Funding Requirement of EE Programs	Low-Income EE Program Requirements	Program Cost Recovery	Lost Margin Recovery	Performance-Based Incentives	Fuel Switching	Full Cycle EE Measurement	EM&V Reporting Requirement
AL										
AK										
AR	•	•	•		•	•				•
AZ	•		•	•	•					•
CA	•	•	•	•	•	•	•		•	•
CO	•	•	•	•	•	•	•	•	•	•
CT	•	•	•	•	•	•				•
DC										
DE										
FL	•		•		•	•		•	•	
GA	•		•			•				•
HI										
IA	•	•	•	•	•					•
ID	•		•		•			•		•
IL	•	•	•	•	•	•				•
IN	•	•			•	•		•	•	•
KS										
KY	•			•	•	•	•			•
LA										
MA	•	•	•	•	•	•	•	•	•	•
MD	•	•	•	•	•	•				•
ME	•		•	•	•					•
MI	•	•	•	•	•	•	•		•	•
MN	•	•	•	•	•	•	•		•	•
MO	•		•	•	•	•				•
MS										
MT	•				•	•				•
NC	•				•	•				•
ND	•				•				•	•
NE										
NH	•	•	•	•	•		•			•
NJ	•	•	•	•	•	•	•	•		•
NM	•		•	•						•
NV	•									
NY	•	•	•	•	•	•	•	•		•
OH	•	•	•	•	•	•				•
OK										
OR	•	•	•	•	•	•		•		•
PA	•	•	•	•	•			•		•
RI	•	•	•	•	•		•			•
SC										
SD	•				•	•				•
TN										
TX	•				•				•	•
UT	•	•		•	•	•			•	•
VA	•		•		•	•				•
VT	•	•	•	•	•			•		•
WA	•	•	•	•	•	•	•	•		•
WI	•	•	•	•	•		•	•		•
WV										
WY	•				•	•			•	•
Canada	•	•	•	•	•	•	•			
States	36	22	28	25	34	23	12	12	11	36

• Existent as of 2009 • Pending regulatory approval as of 2009

APPENDIX B – NATURAL GAS EFFICIENCY PROGRAM 2009 EXPENDITURES AND 2010 BUDGETS BY STATE

Gas Efficiency Program 2009 Expenditures and 2010 Budgets

STATE	A. RESIDENTIAL		B. LOW INCOME		C. COMMERCIAL & INDSUTRIAL		D. OTHER		PROGRAMS TOTAL Including all EMV Dollars[1]	
	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 EXPENDITURES	2010 BUDGETS
ALABAMA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALASKA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ARIZONA	$ 480,407	$ 879,300	$ 493,508	$ 450,000	$ 50,654	$ 1,244,500	$ -	$ -	$ 1,024,569	$ 2,573,800
ARKANSAS	$ 544,080	$ 2,447,825	$ 43,688	$ -	$ 367,099	$ 1,582,010	$ 57,283	$ 75,243	$ 1,012,151	$ 4,165,078
CALIFORNIA	$ 37,920,415	$ 52,123,649	$ 104,344,912	$ 151,428,983	$ 63,890,207	$ 94,300,351	$ 22,087,680	$ 49,919,758	$ 228,268,214	$ 338,827,741
COLORADO	$ 5,633,565	$ 8,870,173	$ 3,106,244	$ 4,194,358	$ 1,053,284	$ 1,877,930	$ 2,789,851	$ 3,426,713	$ 12,582,944	$ 18,369,174
CONNECTICUT	$ 3,181,072	$ 3,693,000	$ 2,464,754	$ 2,325,436	$ 3,530,915	$ 4,769,561	$ 381,261	$ 382,000	$ 9,558,002	$ 10,824,997
DELAWARE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRICT OF COLOMBIA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FLORIDA	$ 5,110,000	$ 5,520,000	$ -	$ -	$ 771,000	$ 1,020,000	$ -	$ -	$ 5,881,000	$ 6,540,000
GEORGIA	$ -	$ -	$ 1,000,000	$ 1,000,000	$ -	$ -	$ -	$ -	$ 1,000,000	$ 1,000,000
IDAHO	$ 1,220,411	$ 787,392	$ 145,954	$ 263,766	$ 809,868	$ 725,520	$ 292,467	$ 300,949	$ 2,468,700	$ 2,077,627
ILLINOIS	$ 4,989,093	$ 10,979,000	$ 948,371	$ 1,693,000	$ 389,442	$ 4,359,000	$ -	$ 250,000	$ 6,326,906	$ 17,281,000
INDIANA	$ 5,712,981	$ 8,536,633	$ 418,136	$ 1,346,429	$ 834,800	$ 1,520,979	$ 2,082,805	$ 2,890,950	$ 9,248,722	$ 14,494,991
IOWA	$ 22,512,244	$ 24,500,907	$ 4,898,404	$ 4,856,010	$ 7,991,932	$ 8,315,519	$ 2,287,226	$ 2,854,868	$ 37,689,806	$ 40,527,304
KANSAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KENTUCKY	$ 9,671	$ 1,184,291	$ 305,211	$ 727,883	$ -	$ -	$ 2,673	$ 20,326	$ 317,555	$ 1,932,500
LOUSIANA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MAINE	$ 493,636	$ 167,565	$ 9,625	$ 28,757	$ 311,116	$ 219,600	$ -	$ -	$ 814,377	$ 415,922
MARYLAND	$ 1,400,000	$ 2,700,000	$ 592,271	$ 690,000	$ -	$ -	$ -	$ -	$ 1,992,271	$ 3,390,000
MASSACHUSETTS	$ 27,947,820	$ 41,021,476	$ 7,016,700	$ 15,780,536	$ 9,157,684	$ 19,050,745	$ -	$ -	$ 44,122,204	$ 75,852,758
MICHIGAN	$ 5,627,422	$ 9,089,629	$ 6,135,900	$ 8,683,451	$ 2,142,435	$ 3,620,481	$ 3,523,029	$ 3,647,291	$ 17,428,786	$ 25,040,852
MINNESOTA	$ 6,222,250	$ 18,223,995	$ 3,309,334	$ 3,253,032	$ 7,177,812	$ 15,074,499	$ 5,687,283	$ 3,537,224	$ 22,396,709	$ 40,088,750
MISSISSIPPI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISSOURI	$ 1,185,816	$ 2,404,747	$ 1,816,554	$ 1,771,500	$ 128,619	$ 659,025	$ 86,587	$ 362,638	$ 3,217,576	$ 5,276,613
MONTANA	$ 108,600	$ 110,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,600	$ 110,000
NEBRASKA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NEVADA	$ 392,507	$ 1,920,500	$ 234,142	$ 445,000	$ -	$ 892,525	$ -	$ 150,000	$ 626,649	$ 3,408,025
NEW HAMPSHIRE	$ 1,117,167	$ 3,651,733	$ 574,409	$ 733,907	$ 1,503,545	$ 5,896,894	$ -	$ -	$ 3,195,121	$ 10,282,534
NEW JERSEY	$ 42,715,543	$ 94,892,891	$ 33,337,031	$ 29,318,547	$ 16,165,430	$ 41,100,637	$ -	$ -	$ 92,515,632	$ 166,660,710
NEW MEXICO	$ 393,270	$ 1,011,233	$ 1,176,749	$ 1,302,142	$ 140,371	$ 228,349	$ -	$ -	$ 1,759,670	$ 2,629,245
NEW YORK	$ 12,590,946	$ 54,100,337	$ 28,633,203	$ 3,507,373	$ 17,406,854	$ 29,888,213	$ -	$ -	$ 58,631,003	$ 87,495,923
NORTH CAROLINA	$ 900,000	$ 900,000	$ 225,000	$ 225,000	$ 150,000	$ 150,000	$ -	$ -	$ 1,275,000	$ 1,275,000
NORTH DAKOTA	$ 112,484	$ 138,260	$ -	$ -	$ -	$ -	$ -	$ -	$ 112,484	$ 138,260
OHIO	$ 3,405,208	$ 4,243,638	$ 3,154,016	$ 5,100,000	$ 207,292	$ 357,000	$ 1,704,167	$ 1,259,362	$ 8,470,683	$ 11,000,000
OKLAHOMA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OREGON	$ 12,681,222	$ 15,257,308	$ 1,536,074	$ 2,277,176	$ 6,275,093	$ 8,917,774	$ 131,143	$ 130,000	$ 21,248,532	$ 27,207,259
PENNSYLVANIA	$ 1,705,200	$ 2,514,000	$ 8,577,842	$ 10,273,974	$ 27,320	$ 36,000	$ 18,965	$ 100,000	$ 10,330,327	$ 12,923,974
RHODE ISLAND	$ 2,626,500	$ 1,404,200	$ 1,310,300	$ 368,200	$ 2,207,600	$ 2,701,700	$ -	$ 108,200	$ 6,144,400	$ 4,582,300
SOUTH CAROLINA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOUTH DAKOTA	$ 691,616	$ 1,203,170	$ 2,481	$ -	$ 70,509	$ 225,396	$ -	$ -	$ 764,606	$ 1,428,566
TENNESSEE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TEXAS	$ 1,369,553	$ 1,301,400	$ 23,403	$ 110,000	$ 171,075	$ 213,500	$ -	$ -	$ 1,578,031	$ 1,639,900
UTAH	$ 44,965,120	$ 32,911,444	$ 500,000	$ 500,000	$ 799,790	$ 1,357,351	$ 1,184,239	$ 1,356,500	$ 47,449,149	$ 36,125,295
VERMONT	$ 1,286,833	$ 1,188,096	$ 80,000	$ 84,600	$ 595,179	$ 861,901	$ -	$ -	$ 1,962,062	$ 2,133,997
VIRGINIA	$ 1,527,627	$ 3,741,917	$ 150,000	$ 387,500	$ -	$ 373,900	$ 481,075	$ 1,652,105	$ 2,158,702	$ 6,155,422
WASHINGTON	$ 4,901,788	$ 2,652,004	$ 858,897	$ 587,701	$ 2,979,379	$ 1,971,537	$ 560,909	$ 3,866,402	$ 9,300,973	$ 9,077,644
WEST VIRGINIA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISCONSIN	$ 10,510,485	$ 9,435,702	$ 36,247,825	$ 33,435,021	$ 15,357,746	$ 12,007,964	$ 8,153,733	$ 8,556,009	$ 71,514,824	$ 64,844,580
WYOMING	$ 4,650	$ 262,772	$ -	$ -	$ -	$ 49,381	$ -	$ 76,168	$ 4,650	$ 388,321
NOT ALLOCABLE BY STATE[2]	$ 22,141,651	$ 37,484,082	$ 21,945,685	$ 26,480,785	$ 7,558,885	$ 12,517,961	$ 6,328,803	$ 9,112,238	$ 58,130,024	$ 85,782,067
CANADA	$ 20,096,628	$ 19,038,903	$ 6,806,786	$ 14,885,635	$ 22,827,837	$ 24,564,318	$ 16,801,888	$ 25,716,708	$ 66,921,355	$ 85,018,163
UNITED STATES	$ 296,339,903	$ 463,454,269	$ 275,616,623	$ 313,629,468	$ 170,223,965	$ 278,087,704	$ 57,841,179	$ 85,104,944	$ 802,631,614	$ 1,143,968,129
NORTH AMERICA[3]	$ 316,435,532	$ 482,493,172	$ 282,423,409	$ 328,515,103	$ 193,051,803	$ 302,652,022	$ 74,643,067	$ 110,821,652	$ 869,552,969	$ 1,228,986,291

[1] Program categories may not add up to the numbers in the Total columns, because these include EM&V dollars that were not reported in the specified categories.

[2] United States total for those survey companies that did not agree to release their data other than as part of a national aggregate.

[3] Total for all participant companies in the United States and Canada that provided 2009 expenditure and/or 2010 budget data.

APPENDIX C – NATURAL GAS EFFICIENCY PROGRAM 2009 EXPENDITURES AND 2010 BUDGETS BY REGION

Gas Efficiency Program 2009 Expenditures and 2010 Budgets										
REGION[2]	A. RESIDENTIAL		B. LOW INCOME		C. COMMERCIAL & INDSUTRIAL		D. OTHER		PROGRAMS TOTAL Including all EMV Dollars[1]	
	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 Expenditures	2010 Budget	2009 EXPENDITURES	2010 BUDGETS
NORTHEAST	93,665,767	202,633,298	82,003,865	62,420,730	50,506,643	104,525,251	400,726	590,200	227,273,128	371,173,114.8
MIDWEST	60,969,599	88,755,681	56,931,021	60,138,443	34,300,617	46,139,863	23,524,830	23,398,342	177,171,102	220,120,916.0
SOUTH	10,860,931	17,795,433	2,339,573	3,140,383	1,459,174	3,339,410	541,031	1,747,674	15,214,709	26,097,900.0
WEST	108,701,955	116,785,775	112,396,480	161,449,126	75,998,646	111,565,219	27,046,289	50,256,490	324,842,650	440,794,130.8
NOT ALLOCABLE BY REGION	22,141,651	37,484,082	21,945,685	26,480,786	7,558,885	12,517,961	6,328,803	9,112,236	58,130,024	85,782,067
CANADA	20,096,628	19,038,903	6,806,786	14,885,635	22,827,637	24,564,316	16,801,888	25,716,708	66,921,355	85,018,163
UNITED STATES[3]	296,339,903	463,454,269	275,616,623	313,629,468	170,223,965	276,087,704	57,841,179	85,104,944	802,631,614	1,143,968,129
NORTH AMERICA[4]	316,436,532	482,493,172	282,423,409	328,515,103	193,051,803	302,652,022	74,643,067	110,821,652	869,552,969	1,228,986,291

[1] Program categories may not add up to the numbers in the Total columns, because these include EM&V dollars that were not reported in the specified categories.

[2] Rows one through four are regional aggregates for companies that have released their data for publication at the state and regional levels and, in many cases, at the company level.

[3] United States total for those survey companies that did not agree to release their data other than as part of a national aggregate.

[4] Total for all participant companies in the United States and Canada that provided 2009 expenditure and/or 2010 budget data.

Appendix D – Natural Gas Efficiency Program Savings Impacts By Region

2009 ESTIMATED ANNUAL GAS EFFICIENCY PROGRAM SAVINGS IMPACTS						
REGION	RESIDENTIAL	LOW INCOME	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL THERM	TRILLION BTU
NORTHEAST	36,647,555	6,561,771	45,276,695	4,035,120	92,521,142	9.25
MIDWEST	62,919,111	14,906,153	37,021,762	496,579	115,343,605	11.53
SOUTH	685,041	2,074,211	31,495	-	2,790,746	0.28
WEST	79,131,009	14,561,118	205,835,648	18,778,278	318,306,053	31.83
CANADA	84,237,984	4,645,501	283,661,332	(3,130,817)	369,414,000	36.94
UNITED STATES	94,529,727	9,564,336	152,638,589	32,871,520	289,604,172	28.96
NORTH AMERICA	115,007,285	10,249,895	210,810,827	31,185,094	367,253,101	36.73

APPENDIX E – SURVEY PARTICIPANT COMPANIES

COMPANY	STATE	COMPANY	STATE
...en Illinois Utilities (Ameren Corporation)	IL	National Fuel Gas Distribution Corporation (National Fuel Gas Company)	NY
...nsas Oklahoma Gas Corporation	AR	National Grid Massachusetts	MA
...nsas Western Gas Co (SourceGas LLC)	AR	National Grid New Hampshire	NH
...nta Gas Light (AGL Resources Inc.)	GA	National Grid New York - Upstate & Downstate (Long Island & New York City)	NY
...os Energy - Colorado	CO	National Grid Rhode Island	RI
...os Energy - Kentucky/Midstates Division	KY	New Jersey Board of Public Utilities (for New Jersey Clean Energy Program)	NJ
...os Energy - KY/Midstates Division - Iowa	IA	New Jersey Natural Gas Company (New Jersey Resources)	NJ
...os Energy - KY/Midstates Division - Missouri	MO	New Mexico Gas Company (Continenal Energy Systems LLC)	NM
...os Energy - Mid-Texas Division	TX	New York State Energy Research and Development Authority (or NYSERDA)	NY
...ta Utilities - Idaho (Avista Corp.)	ID	Nicor Gas (Nicor Inc.)	IL
...ta Utilities - Oregon (Avista Corp.)	OR	North Shore Gas and Peoples Gas (Integrys Energy Group, Inc.)	IL
...ta Utilities - Washington (Avista Corp.)	WA	Northern Indiana Public Service Company (NiSource Inc.)	IN
...more Gas and Electric Corporation (Constellation Energy)	MD	Northern Utilities Inc, Inc. D/B/A Unitil Maine	ME
State Gas Company (NiSource Inc.)	MA	Northern Utilities Inc, Inc. D/B/A Unitil New Hampshire	NH
...shire Gas Company, The (Iberdrola USA, formerly Energy East)	MA	NSTAR Electric & Gas Corporation	MA
...Hills Energy - Iowa (formerly Aquila, Black Hills Corporation)	IA	NV Energy, Inc. (formerly Sierra Pacific Resources)	NV
...Hills Energy Corporation - Colorado (formerly Aquila, Black Hills Corporation)	CO	NW Natural - OR	OR
...ade Natural Gas Corp - Oregon (MDU Resources Group)	OR	NW Natural - WA	WA
...ade Natural Gas Corp - Washington (MDU Resources Group)	WA	Orange & Rockland Utilities, Inc. (Consolidated Edison Inc.)	NY
...terPoint Energy - Arkansas	AR	Pacific Gas and Electric Company (PG&E Corporation)	CA
...terPoint Energy - Minnesota	MN	PECO (Exelon Corporation)	PA
...ens Energy Group	IN	Peoples Natural Gas (formerly Dominion Peoples)	PA
...Gas Company	WI	Philadelphia Gas Works	PA
...of Palo Alto	CA	Piedmont Natural Gas Company, Inc.	NC
...rado Natural Gas, Inc. (Summit Energy)	CO	Public Interest Energy Research Program (PIER)	CA
...mbia Gas of Kentucky (NiSource Inc.)	KY	Public Service Electric and Gas Company (PSEG)	NJ
...mbia Gas of Maryland (NiSource Inc.)	MD	Puget Sound Energy (Puget Energy)	WA
...mbia Gas of Ohio (NiSource Inc.)	OH	Questar Gas Company - Utah	UT
...mbia Gas of Pennsylvania (NiSource Inc.)	PA	Questar Gas Company - Wyoming	WY
...mbia Gas of Virginia (NiSource Inc.)	VA	San Diego Gas & Electric Company (SEMPRA Energy)	CA
...necticut Natural Gas Corp & Southern Connecticut Natural Gas (Iberdrola USA, formerly Energy East)	CT	SaskEnergy	Canada
...solidated Edison of New York (Consolidated Edison, Inc.)	NY	Source Gas Distribution (SourceGas LLC)	CO
...sumers Energy (CMS Energy Corporation)	MI	South Jersey Gas (South Jersey Industries Inc.)	NJ
...Natural Gas Company, Inc.	KY	Southern California Gas Company (SEMPRA Energy)	CA
...inion East Ohio (Dominion Resources, Inc.)	OH	Southwest Gas Corporation - Arizona	AZ
...Energy Corporation - Kentucky	KY	Southwest Gas Corporation - California	CA
...Energy Corporation - Ohio	OH	Southwest Gas Corporation - Nevada	NV
...bethtown Gas (AGL Resources Inc.)	NJ	St. Croix Valley Natural Gas Company, Inc.	WI
...ire District Gas Company (The Empire District Electric Company)	MO	St. Lawrence Gas Company, Inc. (Enbridge Gas Distribution Inc.)	NY
...idge Gas Distribution Inc. (Enbridge Inc.)	Canada	Superior Water, Light & Power Company (ALLETE)	WI
...gy Trust of Oregon	OR	TECO Peoples Gas (TECO Energy, Inc.)	FL
...itable Gas Company LLC - Pennsylvania (EQT Corp.)	PA	Terasen Gas Inc. (Terasen Gas)	Canada
...hburg Gas and Electric Light Company d/b/a Unitil Massachusetts	MA	Texas Gas Service (ONEOK, Inc.)	TX
...t Plains Natural Gas Co (MDU Resources Group)	MN	UGI Utilities, Inc. (UGI Corporation)	PA
...rmountain Gas Company - Idaho (MDU Resources Group)	ID	Union Gas Limited (Spectra Energy)	Canada
...rstate Power and Light Company - Iowa (An Alliant Energy Company)	IA	Vectren Energy Delivery of Indiana (Vectren Corporation)	IN
...rstate Power and Light Company - Minnesota (An Alliant Energy Company)	MN	Vectren Energy Delivery of Ohio (Vectren Corporation)	OH
...ede Gas Company (The LaClede Group Inc.)	MO	Vermont Gas Systems, Inc. (Northern New England Energy Corporation)	VT
...ison Gas and Electric Company (MGE Energy)	WI	Virginia Natural Gas (AGL Resources Inc.)	VA
...itoba Hydro	Canada	Washington Gas Light Company - Maryland (WGL Holdings, Inc.)	MD
...hCon (DTE Energy Corporation)	MI	Washington Gas Light Company - Virginia (WGL Holdings, Inc.)	VA
...igan Gas Utilities (Integrys Energy Group)	MI	We Energies (Wisconsin Energy Group)	WI
...American Energy Company - Illinois	IL	Wisconsin Division of Energy Services	WI
...American Energy Company - Iowa	IA	Wisconsin Energy Conservation Corporation (for Focus on Energy Program)	WI
...American Energy Company - South Dakota	SD	Wisconsin Power and Light, An Alliant Energy Company	WI
...west Natural Gas Corp.	WI	Wisconsin Public Service (Integrys Energy Group)	WI
...nesota Energy Resources Corporation (Integrys Energy Group)	MN	Xcel Energy Inc. - Colorado	CO
...souri Gas Energy (Southern Union Company)	MO	Xcel Energy Inc. - Minnesota	MN
...ntana-Dakota Utilities Co - Montana (MDU Resources Group)	MT	Xcel Energy Inc. - North Dakota	ND
...ntana-Dakota Utilities Co - North Dakota (MDU Resources Group)	ND	Xcel Energy Inc. - Wisconsin	WI
...ntana-Dakota Utilities Co - South Dakota (MDU Resources Group)	SD	Yankee Gas Service (Northeast Utilities)	CT
...ntana-Dakota Utilities Co - Wyoming (MDU Resources Group)	WY		

Appendix A

Understanding Cost-Effectiveness of Energy Efficiency Programs:

Best Practices, Technical Methods, and Emerging Issues for Policy-Makers

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

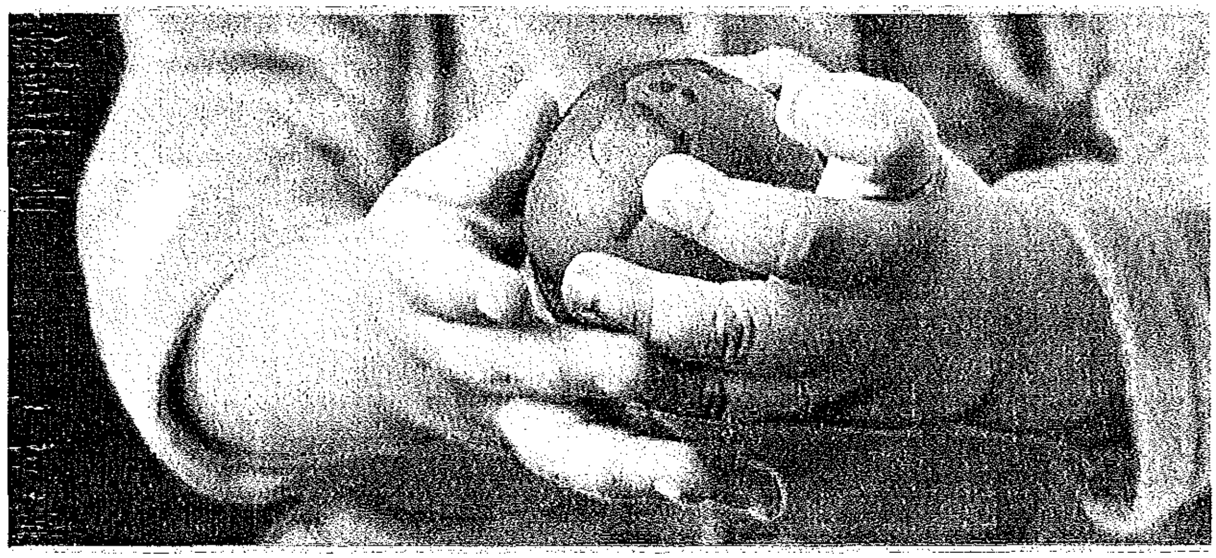
Appendix B

About This Document

This paper, *Understanding Cost-Effectiveness of Energy Efficiency Programs*, is provided to assist utility regulators, gas and electric utilities, and others in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

This paper reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms.

The intended audience for the paper is any stakeholder interested in learning more about how to evaluate energy efficiency through the use of cost-effectiveness tests. All stakeholders, including public utility commissions, city councils, and utilities, can use this paper to understand the key issues and terminology, as well as the various perspectives each cost-effectiveness test provides, and how the cost-effectiveness tests can be implemented to capture additional energy efficiency.



Understanding Cost-Effectiveness of Energy Efficiency Programs:

Best Practices, Technical Methods, and Emerging Issues for Policy-Makers

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

Appendix B

The Leadership Group of the National Action Plan for Energy Efficiency is committed to taking action to increase investment in cost-effective energy efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* was developed under the guidance of and with input from the Leadership Group. The document does not necessarily represent a consensus view and does not represent an endorsement by the organizations of Leadership Group members.

Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers is a product of the National Action Plan for Energy Efficiency and does not reflect the views, policies, or otherwise of the federal government. The role of the U.S. Department of Energy and U.S. Environmental Protection Agency is limited to facilitation of the Action Plan.

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For More Information

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List of Abbreviations and Acronyms

AEO	Annual Energy Outlook
Btu	British thermal unit
CCGT	combined cycle gas turbine
CDM	conservation and demand management
CEC	California Energy Commission
CFL	compact fluorescent light bulb
CO_2	carbon dioxide
DCR	debt-coverage ratio
DOE	U.S. Department of Energy
DR	demand response
DSM	demand-side management
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
HP	horsepower
HVAC	heating, ventilation, and air conditioning
ICAP	installed capacity
IOU	investor-owned utility
IRP	integrated resource planning
kW	kilowatt
kWh	kilowatt-hour
LNG	liquefied natural gas
LSE	load serving entity
MMBtu	million Btu
MW	megawatt
MWh	megawatt-hour
NEBs	non-energy benefits
NO_x	nitrogen oxides
NPV	net present value
NTG	net-to-gross ratio
NWPCC	Northwest Power and Conservation Council
NYSERDA	New York State Energy Research and Development Authority
PACT	program administrator cost test (same as UCT)
PCT	participant cost test
PSE	Puget Sound Energy
RIM	ratepayer impact measure test
ROE	return on equity
RPS	renewable portfolio standard
SCE	Southern California Edison
SCT	societal cost test
SEER	Seasonal Energy Efficiency Ratio
SO_x	sulfur oxides
T&D	transmission and distribution
TOU	time of use
TRC	total resource cost test
TWh	terawatt-hour
UCAP	unforced capacity
UCT	utility cost test (same as PACT)
VOC	volatile organic compound
WACC	weighted average cost of capital

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With direction and comment by the Action Plan Leadership Group, the paper's development was led by Snuller Price, Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency (EPA). Additional preparation was performed by Eric Cutter and Rebecca Ghanadan of Energy and Environmental Economics, Inc.

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Executive Summary

This paper, Understanding Cost-Effectiveness of Energy Efficiency Programs, reviews the issues and approaches involved in considering and adopting cost-effectiveness tests for energy efficiency, including discussing each perspective represented by the five standard cost-effectiveness tests and clarifying key terms. This paper is provided to assist organizations in meeting the 10 implementation goals of the National Action Plan for Energy Efficiency's Vision to achieve all cost-effective energy efficiency by 2025.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Understanding energy efficiency cost-effectiveness tests and the various stakeholder perspectives each test represents is key to establishing the policy framework to capture these benefits.

This paper has been developed to help parties pursue the key policy recommendations and implementation goals of the National Action Plan for Energy Efficiency. The Action Plan was released in July 2006 as a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level. This paper directly supports the National Action Plan's Vision for 2025 implementation goal three, which encourages state agencies along with key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal highlights the policy step to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Evaluating the cost-effectiveness of energy efficiency is essential to identifying how much of our country's potential for energy efficiency resources will be captured. Based on studies, energy efficiency resources may be able to meet 50 percent or more of the expected load growth by 2025 (National Action Plan for Energy Efficiency, 2008). Defining cost-effectiveness helps energy efficiency compete with the broad range of other resource options in order for energy efficiency to get the attention and funding necessary to succeed.

In its simplest form, energy efficiency cost-effectiveness is measured by comparing the benefits of an investment with the costs. Five key cost-effectiveness tests have, with minor updates, been used for over 20 years as the principal approaches for energy efficiency program evaluation. These five cost-effectiveness tests are the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), the total resource cost test (TRC), and the societal cost test (SCT).

The key points from this paper include:

- There is no single best test for evaluating the cost-effectiveness of energy efficiency.

- Each of the cost-effectiveness tests provides different information about the impacts of energy efficiency programs from distinct vantage points in the energy system. Together, multiple tests provide a comprehensive approach.

- Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on a par with other resources.

- The most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The distributional tests (PCT, PACT, and RIM) are then used to indicate how different stakeholders are affected. Historically, reliance on the RIM test has limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests.

There are a number of choices in developing the costs and benefits of energy efficiency that can significantly affect the cost-effectiveness results. Several major choices available to utilities, analysts, and policy-makers are described below.

- **Where in the process to apply the cost-effectiveness tests:** The choice of where to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: at the "measure" level, the "program" level, and the "portfolio" level. Applying cost-effectiveness tests at the program or portfolio levels allows some non-cost-effective measures or programs to be offered as long as their shortfall is more than offset by cost-effective measures and programs.

- **Which benefits to include:** There are two main categories of avoided costs: energy-related and capacity-related. Energy-related avoided costs refer to market prices of energy, fuel costs, natural gas commodity prices, and other variable costs. Capacity-related avoided costs refer to infrastructure investments such as power plants, transmission and distribution lines, and pipelines. From an environmental point of view, saving energy reduces air emissions, including greenhouse gases (GHGs). Within each of these categories, policy-makers must decide which specific benefits are sufficiently known and quantifiable to be included in the cost-effectiveness evaluation.

- **Net present value and discount rates:** A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption used to calculate the net present value (NPV) of the annual costs and benefits. Since costs typically occur upfront and savings occur over time, the lower the discount rate the more likely the cost-effectiveness result is to be positive. As each cost-effectiveness test portrays a specific stakeholder's view, each cost-effectiveness test should use the discount rate associated with its perspective. For a household, the consumer lending rate is used, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. For a business firm, the discount rate is the firm's weighted average cost of capital, typically in the 10 to 12 percent range. However, commercial and industrial customers often demand payback periods of two years or less, implying a discount rate well in excess of 20 percent. The PACT, RIM, and TRC should reflect the utility weighted average cost of capital. The social discount rate (typically the lowest rate) should be used for the SCT to reflect the benefit to society over the long term.

- **Net-to-gross ratio (NTG):** The NTG can be a significant driver in the results of TRC, PACT, RIM, and SCT. The NTG adjusts the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the energy efficiency program. Therefore, the NTG deducts energy savings that would have been achieved without the efficiency program (e.g., "free-riders") and increases savings for any "spillover" effect that occurs as an indirect result of the program. Since the NTG attempts to measure what customers would have done in the absence of the energy efficiency program, it can be difficult to determine precisely.

- **Non-energy benefits (NEBs):** Energy efficiency measures often have additional benefits (and costs) beyond energy savings, such as improved comfort, productivity, health, convenience and aesthetics. However, these benefits can be difficult to quantify. Some jurisdictions choose to include NEBs and costs in some of the cost-effectiveness tests, often focusing on specific issues emphasized in state policy.

- **GHG emissions:** There is increasing interest in valuing the energy efficiency's effect on reducing GHG emissions in the cost-effectiveness tests. The first step is to determine the quantity of avoided carbon dioxide (CO_2) emissions from the efficiency program. Once the amount of CO_2 reductions has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations and some do not.

- **Renewable portfolio standards (RPS):** The interdependence between energy efficiency and RPS goals is an emerging issue in energy efficiency. Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets. This reduces RPS compliance cost, which is a benefit that should be considered in energy efficiency cost-effectiveness evaluation.

Appendix B

1: Introduction

Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change. Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants.[1]

Recognizing this large opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency. The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency; outlines five policy recommendations for achieving all cost-effective energy efficiency; and offers a wealth of resources and tools for parties to advance these recommendations, including a Vision for 2025. As of November 2008, over 120 organizations have endorsed the Action Plan recommendations and made public commitments to implement them in their areas. Establishing cost-effectiveness tests for energy efficiency investments is key to making the Action Plan a reality.

1.1 Background on Cost-effectiveness Tests

The question of how to define the cost-effectiveness of energy efficiency investments is a critical issue to address when advancing energy efficiency as a key resource in meeting future energy needs. How cost-effectiveness is defined substantially affects how much of our nation's efficiency potential will be accessed and whether consumers will benefit from the lower energy costs and environmental impacts that would result. The decisions on how to define cost-effectiveness or which tests to use are largely made by state utility commissions and their utilities, and with critical input from consumers and other stakeholders. This paper is provided to help facilitate these discussions.

Cost-effectiveness in its simplest form is a measure of whether an investment's benefits exceed its costs. Key differences among the cost-effectiveness tests that are currently used include the following:

- **The stakeholder perspective of the test.** Is it from the perspective of an energy efficiency program participant, the organization offering the energy efficiency program, a non-participating ratepayer, or society in general? Each of these perspectives represents a valid viewpoint and has a role in assessing energy efficiency programs.

- **The key elements included in the costs and the benefits.** Do they reflect avoided energy use, incentives for energy efficiency, avoided need for new generation and new transmission and distribution, and avoided environmental impacts?

- **The baseline against which the cost and benefits are measured.** What costs and benefits would have been realized absent investment in energy efficiency?

The five cost-effectiveness tests commonly used across the country are listed below:

- Participant cost test (PCT).
- Program administrator cost test (PACT).[2]
- Ratepayer impact measure test (RIM).
- Total resource cost test (TRC).
- Societal cost test (SCT).

These cost-effectiveness tests are used differently in different states. Some states require all of the tests, some require no specific tests, and others designate a primary test. Table 1-1 provides a quick overview of which tests are used in which states. Chapter 5 presents more information and guidelines on the use of the cost-effectiveness tests by the states.

Table 1-1. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, CT, HI, IA, IN, MN, NO, NV, OR, UT, VA, TX	AR, DC, FL, GA, HI, IA, IN, KS, MN, NH, VA	AR, CA, CO, CT, DE, FL, GA, HI, IL, IN, KS, MA, MN, MO, MT, NH, NM, NY, UT, VA	AZ, CO, GA, HI, IA, IN, MW, ME, MN, MT, NV, OR, VA, VT, WI

Source: Regulatory Assistance Project (RAP) analysis.

Note: Boldface indicates the primary cost-effectiveness test used by each state.

1.2 About the Paper

This paper examines the five standard cost-effectiveness tests that are regularly used to assess the cost-effectiveness of energy efficiency, the perspectives each test represents, and how states are currently using the tests. It also discusses how the tests can be used to provide a more comprehensive picture of the cost-effectiveness of energy efficiency as a resource. Use of a single cost-effectiveness test as a primary cost-effectiveness test may lead to an efficiency portfolio that does not balance the benefits and costs between stakeholder perspectives. Overall, using all five cost-effectiveness tests provides a more comprehensive picture than using any one test alone.

> **Paper Objective**
>
> After reading this paper, the reader should be able to understand the perspective represented by each of the five standard cost tests, understand that all five tests provide a more comprehensive picture than any one test alone, have clarity around key terms and definitions, and use this information to shape how the cost-effectiveness of energy efficiency programs is treated.

This paper was prepared in response to a need identified by the Action Plan Leadership Group (see Appendix A) for a practical discussion of the key considerations and technical terms involved in defining cost-effectiveness and establishing which cost-effectiveness tests to use in developing an energy efficiency program portfolio. The Leadership Group offers this reference to program designers and policy-makers who are involved in adopting and implementing cost-effectiveness tests for evaluating efficiency investments.

This paper supports the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change* (National Action Plan for Energy Efficiency, 2008). This Vision establishes a long-term aspirational goal to achieve all cost-effective energy efficiency by 2025 and outlines 10 goals for implementing the Leadership Group's recommendations (see Figure 1-1). This paper directly supports the Vision's third implementation goal, which encourages states and key stakeholders to establish cost-effectiveness tests for energy efficiency. This goal encourages applicable state agencies, along with key stakeholders, to establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.

Figure 1-1. Ten Implementation Goals of the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change*

Goal One:	Establishing Cost-Effective Energy Efficiency as a High-Priority
Goal Two:	Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field
Goal Three:	Establishing Cost-Effectiveness Tests
Goal Four:	Establishing Evaluation, Measurement, and Verification Mechanisms
Goal Five:	Establishing Effective Energy Efficiency Delivery Mechanisms
Goal Six:	Developing State Policies to Ensure Robust Energy Efficiency Practices
Goal Seven:	Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency
Goal Eight:	Establishing State of the Art Billing Systems
Goal Nine:	Implementing State of the Art Efficiency Information Sharing and Delivery Systems
Goal Ten:	Implementing Advanced Technologies

1.3 Structure of the Paper

This paper walks the reader through the basics of cost-effectiveness tests and the perspectives they represent, issues in determining the costs and benefits to include in the cost-effectiveness tests, emerging issues, how states are currently using cost-effectiveness tests, and guidelines for policy-makers.

The key chapters of the paper are the following:

- Chapter 2. This chapter discusses the five standard cost-effectiveness tests and their application in four utility best practice programs.
- Chapter 3. This chapter briefly describes the interpretation of each test and presents a calculation of each cost-effectiveness test using an example residential program from Southern California Edison.

- **Chapter 4.** This chapter presents the key factors and issues in the determination of an energy efficiency program's cost-effectiveness. It also discusses key emerging issues that are shaping energy efficiency programs, including the impact greenhouse gas (GHG) reduction targets and renewable portfolio standards (RPS) may have on energy efficiency programs.

- **Chapter 5.** This chapter gives guidelines and examples for policy-makers to consider when choosing which cost-effectiveness test(s) to emphasize, and summarizes of the use of the cost-effectiveness tests in each state.

- **Chapter 6.** This chapter describes the calculation of each cost-effectiveness test in detail, as well as the key considerations when reviewing and using cost-effectiveness tests and the pros and cons of each test in relation to increased efficiency investment.

- **Appendix C.** This chapter gives further detail on the four example programs included in Chapter 2. It also describes how the cost-effectiveness test results were calculated for each program.

1.4 Development of the Paper

Understanding Cost-Effectiveness of Energy Efficiency Programs is a product of the Year Three Work Plan for the National Action Plan for Energy Efficiency. With direction and comment by the Action Plan Leadership Group (see Appendix A for a list of group members), the paper's development was led by Snuller Price, Eric Cutter, and Rebecca Ghanadan of Energy and Environmental Economics, Inc., under contract to the U.S. Environmental Protection Agency and the U.S. Department of Energy. Chapter 5 was authored by Rich Sedano and Brenda Hausauer of the Regulatory Assistance Project, under contract to the U.S. Department of Energy.

1.5 Notes

1 See the *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change* (National Action Plan for Energy Efficiency, 2008).

2 The program administrator cost test, or PACT, was originally named the utility cost test (UCT). As program management has expanded to government agencies, nonprofit groups, and other parties, the term "program administrator cost test" has come into use, but the computations are the same. This document refers to the UCT/PACT as the "PACT" for simplicity. See Section 6.2 for more information on the test.

2: Getting Started: Overview of the Cost-Effectiveness Tests

This chapter provides a brief overview of the cost-effectiveness tests used to evaluate energy efficiency measures and programs. All the cost-effectiveness tests use the same fundamental approach in comparing costs and benefits. However, each test is designed to address different questions regarding the cost-effectiveness of energy efficiency programs.

2.1 Structure of the Cost-Effectiveness Tests

Each of the tests provides a different kind of information about the impacts of energy efficiency programs from different vantage points in the energy system. On its own, each test provides a single stakeholder perspective. Together, multiple tests provide a comprehensive approach for asking: Is the program effective overall? Is it balanced? Are some costs or incentives too high or too low? What is the effect on rates? What adjustments are needed to improve the alignment? Each test contributes one of the aspects necessary to understanding these questions and answering them.

The basic structure of each cost-effectiveness test involves a calculation of the total benefits and the total costs in dollar terms from a certain vantage point to determine whether or not the overall benefits exceed the costs. A test is positive if the benefit-to-cost ratio is greater than one, and negative if it is less than one. Results are reported either in net present value (NPV) dollars (method by difference) or as a ratio (i.e., benefits/costs). Table 2-1 outlines the basic approach underlying cost-effectiveness tests.

Table 2-1. Basic Approach for Calculating and Representing Cost-Effectiveness Tests

Net Benefits (Difference)	Net Benefits$_a$ (dollars)	=	NPV $\sum$ benefits$_a$ (dollars) - NPV $\sum$ costs$_a$ (dollars)
Benefit-Cost Ratio	Benefit-Cost Ratio$_a$	=	$\frac{\text{NPV} \sum \text{benefits}_a \text{ (dollars)}}{\text{NPV} \sum \text{costs}_a \text{ (dollars)}}$

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: "NPV" refers to the net present value of benefits and costs. See Section 4.6.

Cost-effectiveness test results compare relative benefits and costs from different perspectives. A benefit-cost ratio above 1 means the program has positive net benefits. A benefit-cost ratio below 1 means the costs exceed the benefits. A first step in analyzing programs is to see which cost-effectiveness tests are produce results above or below 1.

2.2 The Five Cost-Effectiveness Tests and Their Origins

Currently, five key tests are used to compare the costs and benefits of energy efficiency and demand response programs. These tests all originated in California. In 1974, the Warren Alquist Act established the California Energy Commission (CEC) and specified cost-effectiveness as a leading resource planning principle. In 1983, California's *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* manual developed five cost-effectiveness tests for evaluating energy efficiency programs. These approaches, with minor updates, continue to be used today and are the principal approaches used for evaluating energy efficiency programs across the United States.[1]

Table 2-2 summarizes the five tests in terms of the questions they help answer and the key elements of the comparison.

Table 2-2. The Five Principal Cost-Effectiveness Tests Used in Energy Efficiency

Test	Acronym	Key Question Answered	Summary Approach
Participant cost test	PCT	Will the participants benefit over the measure life?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test	PACT	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	RIM	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply-side resource costs
Total resource cost test	TRC	Will the total costs of energy in the utility service territory decrease?	Comparison of program administrator and customer costs to utility resource savings
Societal cost test	SCT	Is the utility, state, or nation better off as a whole?	Comparison of society's costs of energy efficiency to resource savings and non-cash costs and benefits

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

2.3 Cost-Effectiveness Test Results in Best Practice Programs

Illustrating cost-effectiveness test calculations, Table 2-3 shows benefit-cost ratio results from four successful energy efficiency programs from across the country.[2] The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances. Avista's results are for its Regular Income Portfolio, which includes a variety of programs targeted to residential users. Puget Sound Energy's Commercial/Industrial Retrofit Program encourages commercial customers to install cost- and energy-efficient equipment, adopt energy-efficient designs, and use energy-efficient operations at their facilities. Finally, the National Grid's MassSAVE residential program provides residential in-home audits and incentives for comprehensive whole-house improvements.

All the programs presented have been determined to be cost-effective by the relevant utilities[3] and regulators. Nevertheless, the results of the five cost-effectiveness tests vary significantly for each program. Furthermore, the result of each cost-effectiveness test across the four programs is also quite different. (Puget Sound Energy is the only utility for which all five cost-effectiveness tests are positive.) The test results show a range of values that reflect the program designs and the individual choices made by the program administrators and policy-makers for their evaluation. As later chapters discuss, both the individual tests *and* the relationships between test results offer useful information for assessing programs.

Table 2-3. Summary of Cost-effectiveness Test Results for Four Energy Efficiency Programs

Test	Southern California Edison Residential Energy Efficiency Incentive Program	Avista Regular Income Portfolio	Puget Sound Energy Commercial/ Industrial Retrofit Program	National Grid MassSAVE Residential
	Benefit-Cost Ratio			
PCT	7.14	3.47	1.72	8.81
PACT	9.91	4.18	4.19	2.64
RIM	0.63	0.85	1.15	0.54
TRC	4.21	2.26	1.90	1.73
SCT	4.21	2.26	1.90	1.75

Source: E3 analysis: see Appendix C.

Note: The calculation of each cost-effectiveness test varies slightly by jurisdiction. See Appendix C for more details.

The choice of cost-effectiveness test depends on the policy goals and circumstances of a given program and state. Multiple tests yield a more comprehensive assessment than any test on its own.

2.4 Notes

1 The California standard practice manual was first developed in February 1983. It was later revised and updated in 1987–88 and 2001; a Correction Memo was issued in 2007. The 2001 California SPM and 2007 Correction Memo can be found at <http://www.cpuc.ca.gov/PUC/energy/electric/Energy+Efficiency/EM+and+V/>.

2 The cost-effectiveness test results of each program are described further in Appendix C.

3 "Utility" refers to any organization that delivers electric and gas utility services to end users, including investor-owned, cooperatively owned, and publicly owned utilities.

Appendix B

3: Cost-Effectiveness Test Review—Interpreting the Results

This chapter discusses the benefit and cost components included in each cost-effectiveness test, and profiles how a residential lighting and appliance incentive program fares under each test. It also provides an overview of important considerations when using cost-effectiveness tests.

Overall, the results of all five cost-effectiveness tests provide a more comprehensive picture than the use of any one test alone. The TRC and SCT cost tests help to answer whether energy efficiency is cost-effective overall. The PCT, PACT, and RIM help to answer whether the selection of measures and design of the program is balanced from participant, utility, and non-participant perspectives respectively. Looking at the cost-effectiveness tests together helps to characterize the attributes of a program or measure to enable decision making, to determine whether some measures or programs are too costly, whether some costs or incentives are too high or too low, and what adjustments need to be made to improve distribution of costs and benefits among stakeholders. The scope of the benefit and cost components included in each test is summarized in Table 3-1 and Table 3-2.

The broad categories of costs and benefits included in each cost-effectiveness test are consistent across all regions and applications. However, the specific components included in each test may vary across different regions, market structures, and utility types. Transmission and distribution investment may be considered deferrable through energy efficiency in some areas and not in others. Likewise, the TRC and SCT may consider just natural gas or electricity resource savings in some cases, but also include co-benefits of other savings streams (such as water and fuel oil) in others. Considerations regarding the application of each cost-effectiveness test and which cost and benefit components to include are the subject of Chapter 5.

3.1 Example: Southern California Edison Residential Energy Efficiency Program

The Southern California Edison (SCE) Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a statewide mass market efficiency program that coordinates marketing and outreach efforts. This section summarizes how to calculate cost-effectiveness for each cost-effectiveness test using the SCE Residential Energy Efficiency Incentive Program as an example. Calculations for three additional programs from other utilities are evaluated in Appendix C.

Table 3-1. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Test	Benefits	Costs
PCT	*Benefits and costs from the perspective of the customer installing the measure*	
	• Incentive payments • Bill savings • Applicable tax credits or incentives	• Incremental equipment costs • Incremental installation costs
PACT	*Perspective of utility, government agency, or third party implementing the program*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs
RIM	*Impact of efficiency measure on non-participating ratepayers overall*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills
TRC	*Benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility service territory*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Monetized environmental and non-energy benefits (see Section 4.9) • Applicable tax credits (see Section 6.4)	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)
SCT	*Benefits and costs to all in the utility service territory, state, or nation as a whole*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and water if utility is electric) • Non-monetized benefits (and costs) such as cleaner air or health impacts	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Table 3-2. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Component	PCT	PACT	RIM	TRC	SCT
Energy- and capacity-related avoided costs		Benefit	Benefit	Benefit	Benefit
Additional resource savings				Benefit	Benefit
Non-monetized benefits					Benefit
Incremental equipment and installation costs	Cost			Cost	
Program overhead costs		Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost		
Bill savings	Benefit		Cost		

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: Incentive payments include any equipment and installation costs paid by the program administrator.

3.1.1 Overview of the Program

The SCE Residential Energy Efficiency Incentive Program resulted in costs of:

- $3.5 million in administration and marketing for SCE.
- $15.5 million in customer incentives, direct installation, and upstream payments combined for SCE.
- $41.1 million in measure installation costs for customers (before incentives).

The reduced energy consumption achieved as a result of the program resulted in:

- $188 million in avoided cost savings to the utility.
- $278 million in bill savings to the customers (and reduced revenue to SCE).
- Reduced nitrogen oxides (NO_x), PM_{10},[1] and carbon dioxide (CO_2) emissions.

The costs and savings are presented on a "net" basis, after the application of the net-to-gross ratio (NTG). The determination of the NTG is described in Section 4.7. The benefits and costs of the SCE program are presented in Table 3-3 and Table 3-4. Together, these two tables provide the key parameters for employing individual cost-effectiveness tests, as well as the calculations leading to each test are discussed in turn.

Table 3-3. SCE Residential Energy Efficiency Incentive Program Benefits

Net Benefit Inputs		
Resource savings	Units	$
Energy (MWh)	2,795,290	$ 187,904,906
Peak demand (kW)	55,067	—
Total resource savings		$ 187,904,906
Participant bill savings		$ 278,187,587
Emission savings	Tons	
NO_x	421,633	
PM_{10}	203,065	
CO_2	1,576,374	

Source: E3 analysis; see Appendix C.

Table 3-4. SCE Residential Energy Efficiency Incentive Program Costs

Cost Inputs	
Program overhead	
Program administration	$ 898,548
Marketing and outreach	$ 559,503
Rebate processing	$ 1,044,539
Other	$ 992,029
Total program administration	$ 3,494,619
Program incentives	
Rebates and incentives	$ 1,269,393
Direct installation costs	$ 564,027
Upstream payments	$ 13,624,460
Total incentives	$ 15,457,880
Total program costs	$ 18,952,499
Net measure equipment and installation	$ 41,102,993

Source: E3 analysis; see Appendix C.

3.1.2 Cost-Effectiveness Test Results Overview

The results of each of the five cost-effectiveness tests for 2006 (based on the information in the fourth quarter 2006 SCE filing) are presented in Table 3-5[2] A first level assessment shows that the SCE program is very cost-effective for the participant (PCT), the utility (PACT), and the region as a whole (TRC). The program will reduce average energy bills, and a RIM below 1.0 suggests that the program will increase customer rates. Greater detail on the application of each of these cost-effectiveness tests is provided below.

Table 3-5. Summary of Cost-Effectiveness Test Results ($Million)

Test	Cost	Benefits	Ratio	Result
PCT	$41	$294	7.14	Bill savings are more than seven times greater than customer costs.
PACT	$19	$188	9.91	The value of saved energy is nearly 10 times greater than the program cost.
RIM	$297	$188	0.63	The reduced revenue and program cost is greater than utility savings.
TRC	$45	$188	4.21	Overall benefits are four times greater than the total costs.
SCT	$45	$188	4.21	Same as the TRC, as no additional benefits are currently included in the SCT in California.

Source: E3 analysis; see Appendix C.

3.1.3 Calculating the PCT

The PCT assesses the costs and benefits from the perspective of the customer installing the measure. Overall, customers received $294 million in benefits (derived from utility program incentives and bill savings from reduced energy use). The incremental costs to customers were $41 million. This yields an overall net benefit of $252 million and a benefit-cost ratio of 7.14. The PCT shows that bill savings are seven times customer costs—a cost-effective program for the participant. PCT calculation terms from the SCE program data are presented in Table 3-6.

Table 3-6. Participant Cost Test for SCE Residential Energy Efficiency Program

PCT Calculations		
	Benefits	Costs
Program overhead		
Program incentives	$ 15,457,880	
Measure costs		$ 41,102,993
Energy savings		
Bill savings	$ 278,187,587	
Monetized emissions		
Non-energy benefits		
Total	$ 293,645,466	$ 41,102,993
Net benefit	$252,542,473	
Benefit-cost ratio	7.1	

Source: E3 analysis; see Appendix C.

3.1.4 Calculating the PACT

The PACT calculates the costs and benefits of the program from the perspective of SCE as the utility implementing the program. SCE's avoided costs of energy are $188 million (energy savings). Overhead and incentive costs to SCE are $19 million. These figures yield an overall net benefit of $169 million and a benefit-to-cost ratio of 9.91. The PACT result shows that the value of saved energy is nearly 10 times greater than the program cost: high cost-effectiveness from the perspective of the utility's administration of the program. Table 3-7 shows the breakdown of costs and benefits yielding the positive PACT result.

Table 3-7. Program Administrator Cost Test for SCE Residential Efficiency Program

PACT Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	$ 187,904,906	$ 18,952,499
Net benefit	$168,952,407	
Benefit-cost ratio	9.91	

Source: E3 analysis; see Appendix C.

3.1.5 Calculating the RIM

The RIM examines the potential impact the energy efficiency program has on rates overall. The net benefits are the avoided cost of energy (same as PACT). The net costs include the overhead and incentive costs (same as PACT), but also include utility lost revenues from customer bill savings. The result of the SCE program is a loss of $109 million and a benefit-to-cost ratio of 0.63. This result suggests that, all other things being equal, the hypothetical impact of the program on rates would be for rates to increase. However, in practice, non-participants are unaffected until rates are adjusted through a rate case or a decoupling mechanism. In the long term, energy efficiency may reduce the capacity needs of the system; this can lead to either higher or lower rates to non-participants depending on the level of capital costs saved. Energy efficiency can be a lower-cost investment than other supply-side resources to meet customer demand, thereby keeping rates lower than they otherwise would be. (This is discussed in more detail in Section 3.2.2.) Thus it is important to recognize the RIM as examining the potential impacts on rates, but also recognizing that a negative RIM does not necessarily mean that rates will actually increase. Section 6.3 discusses impacts over time in greater detail. Table 3-8 breaks down the costs and benefits included in the RIM.

Table 3-8. Ratepayer Impact Measure for SCE Residential Energy Efficiency Program

RIM Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		$ 15,457,880
Measure costs		
Energy savings (net)	$ 187,904,906	
Bill savings (net)		$ 278,187,587
Monetized emissions (net)	$ 0	
Non-energy benefits		
Total	$ 187,904,906	$ 297,140,085
Net benefit	($109,235,180)	
Benefit-cost ratio	0.63	

Source: E3 analysis: see Appendix C.

3.1.6 Calculating the TRC

The TRC reflects the total benefits and costs to all customers (participants and non-participants) in the SCE service territory. The key difference between the TRC and the PACT is that the former does not include program incentives, which are considered zero net transfers in a regional perspective (i.e., costs to the utility and benefits to the customers). Instead, the TRC includes the net measure costs of $41 million. Net benefits in the TRC are the avoided costs of energy, $188 million. The regional perspective yields an overall benefit of $143 million and a benefit-to-cost ratio of 4.21. In California, the TRC includes an adder that internalizes the benefits of avoiding the emission of NO_x, CO_2, sulfur oxides (SO_x), and volatile organic compounds (VOCs). The adder is incorporated into energy savings (and not broken out as a separate category).[3] In many jurisdictions, the avoided costs are based on a market price that is presumed to implicitly include emissions permit costs and an explicit calculation of permit costs for regulated emissions is not made. The TRC shows that overall benefits are four times greater than total costs (a lower benefits-to-cost ratio than the PACT and PCT, but still positive overall). Table 3-9 shows the costs and benefits included in the TRC calculation.

Table 3-9. Total Resource Cost Test for SCE Residential Energy Efficiency Program

TRC Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits		
Total	$ 187,904,906	$ 44,597,612
Net benefit	$143,307,294	
Benefit-cost ratio	4.21	

Source: E3 analysis; see Appendix C.

3.1.7 Calculating the SCT

In California, the avoided costs of emissions are included directly in energy savings. These benefits are included in both TRC and SCT values, and as a result, their test outputs are the same (see Table 3-10).

Table 3-10. Societal Cost Test for SCE Residential Energy Efficiency Program

SCT Calculations		
	Benefits	Costs
Program overhead		$ 3,494,619
Program incentives		
Measure costs (net)		$ 41,102,993
Energy savings (net)	$ 187,904,906	
Bill savings		
Monetized emissions (net)	(included in energy savings above)	
Non-energy benefits (net)	$ 0	
Total	$ 187,904,906	$ 44,597,612
Net benefit	$143,307,294	
Benefit-cost ratio	4.21	

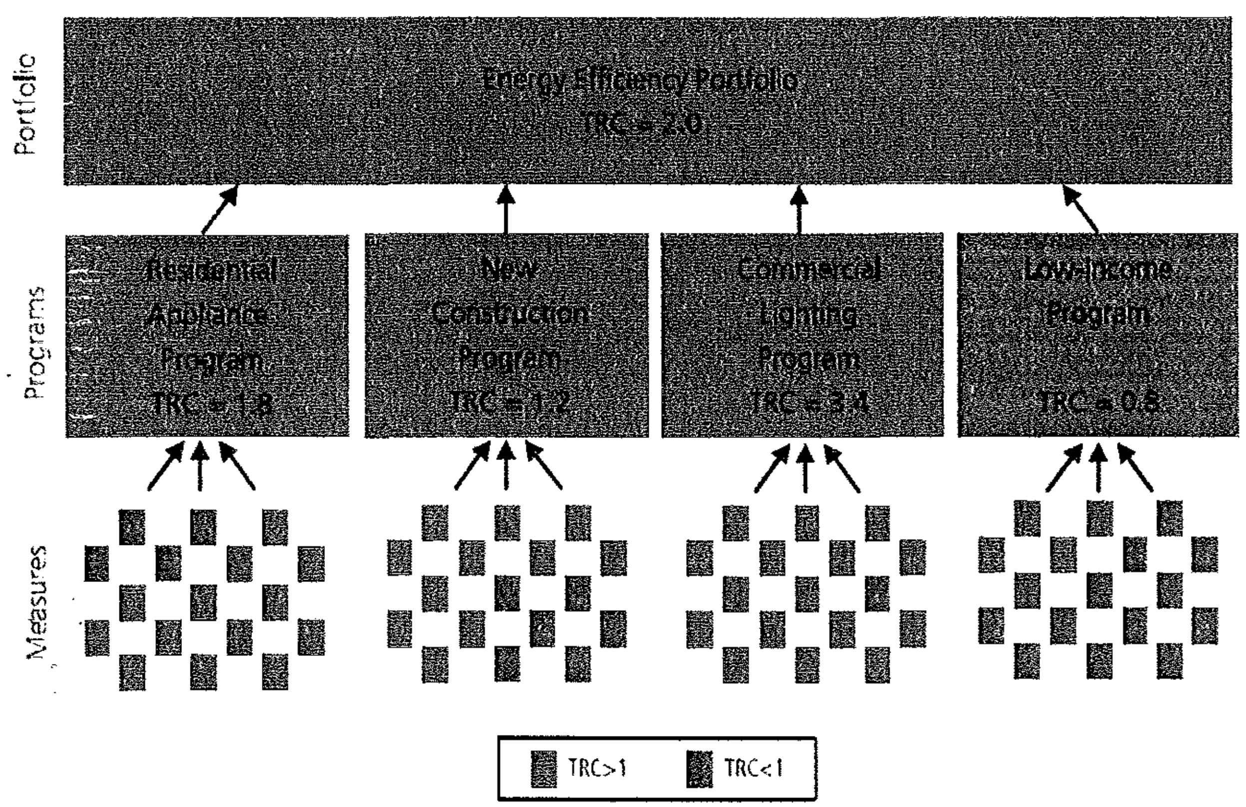
Source: E3 analysis; see Appendix C.

3.2 Considerations When Using Cost-Effectiveness Tests

3.2.1 Application of Cost-Effectiveness Tests

Cost-effectiveness tests can be applied at different points in the design of the energy efficiency portfolio, and the choice of when to apply each cost-effectiveness test has a significant impact on the ultimate set of measures offered to customers. In general, there are three places to evaluate the cost-effectiveness test: the "measure" level, the "program" level, and at the "portfolio" level. Evaluating cost-effectiveness at the measure level means that each individual component of a utility program must be cost-effective. Evaluation at the utility program level means that collectively the measures under a program must be cost-effective, but some measures can be uneconomical if there are other measures that more than make up for them. Evaluating cost-effectiveness at the portfolio level means that all of the programs taken together must be cost-effective, but individual programs can be positive or negative. Figure 3-1 illustrates a hypothetical portfolio in which cost-effectiveness is evaluated at the portfolio level, allowing some measures and programs that are not cost-effective even as the overall portfolio remains positive. If cost-effectiveness were evaluated at a measure level, those measures in red—the low-income program—could be eliminated as not cost-effective and would not be offered to customers.

Figure 3-1. Hypothetical Cost-Effectiveness at Measure, Program, and Portfolio Levels



Applying cost-effectiveness tests at the measure level is the most restrictive. With this approach, the analyst or policy-maker is explicitly or implicitly emphasizing the cost-effectiveness rather than the total energy savings of the efficiency portfolio. In contrast, applying cost-effectiveness tests at the portfolio level allows utilities greater flexibility to experiment with different strategies and technologies and results in greater overall energy savings, though at the expense of a less cost-effective portfolio overall. California applies the cost-effectiveness tests at the portfolio level specifically to allow and encourage the implementation of emerging technology and market transformation programs that promote important policy goals but do not themselves pass the TRC or PCT.

Strictly applying cost-effectiveness at the measure or even the program level can often result in the need for specific exceptions. At the measure level, variations in climate, building vintage, building type and end use may affect the cost-effectiveness of a measure. For marketing clarity, a rebate might be provided service-territory-wide even if some eligible climate zones and customer types are not cost-effective since differentiating among customer types may complicate the advertising message and make the program less effective (the program designers make sure the measure is cost-effective overall). At the program level, some programs—such as low-income programs—generally need higher incentive levels and marketing focus and may not be cost-effective, but are desired in the overall portfolio for social equity and other policy reasons. Similarly, some programs, such as those for emerging technologies or Home Performance with ENERGY STAR, ramp up slowly over time and typically do not achieve cost-effectiveness within the first three years, but do provide energy efficiency benefits. Also, the program and portfolio approaches make it easier to include supporting programs such as informational campaigns that raise overall awareness and complement other programs, but may not be cost-effective on a stand-alone basis.

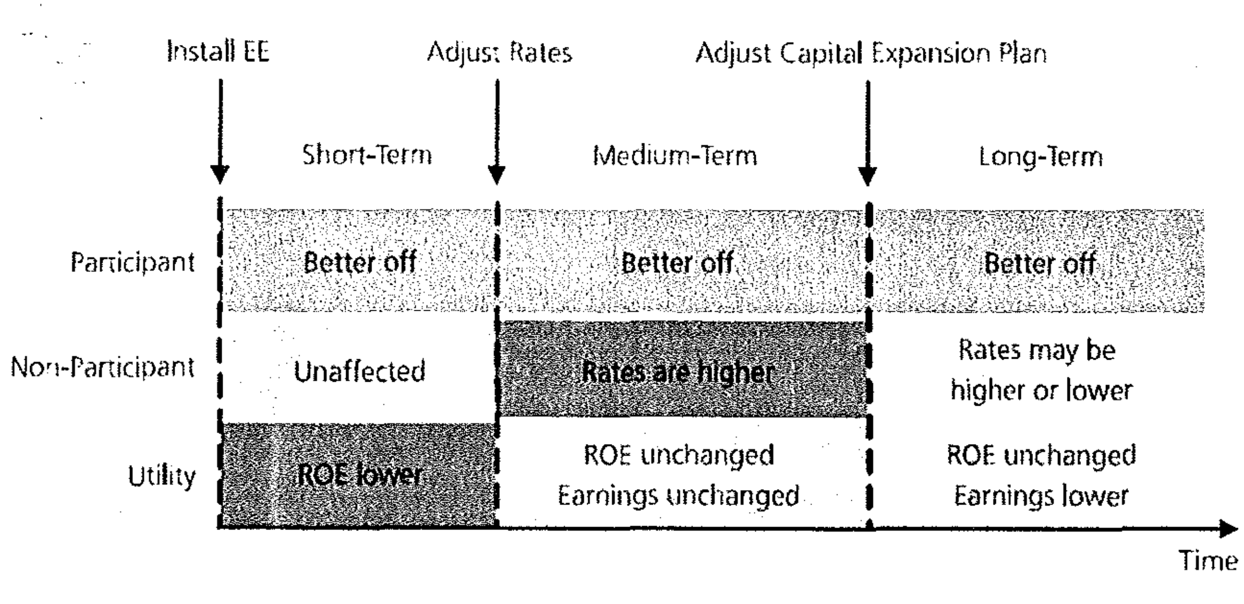
Summing up the benefits of multiple measures at the program level may require some adjustment for what are known as "interactive effects" between related measures. Interactive effects occur when multiple measures installed together affect each other's impacts. When measures affect the same end use, their combined effect when implemented together may be less than the sum of each measure's individually estimated impact. An insulation and air conditioning measure may each save 500 kilowatt-hours (kWh) individually, but less than 1,000 kWh when installed together. Alternatively, some measures may have additional benefits when other end uses are also present (i.e., "interactive effects"). For example, replacing incandescent bulbs with compact fluorescent light bulbs (CFLs) also reduces cooling loads in buildings with air conditioning.

3.2.2 Impacts Over Time of the Distribution Tests

Cost-effectiveness tests are evaluated on a life-cycle basis; however, they do not show the way impacts vary or adjust over time. As a result, it is important to recognize the ways in which program impacts may vary over time in order to properly interpret cost-effectiveness test results. For example, the RIM estimates the impact of the energy efficiency program on non-participants. Yet non-participants are actually unaffected until rates are adjusted through a rate case or a decoupling mechanism. Figure 3-2 illustrates the distributional impacts on the participant, non-participant, and utility over time in the common test-result case where energy efficiency has a PCT above 1 and a RIM below 1.[4]

Consider three time periods from the point at which the energy efficiency measure is first installed: the short term, medium term, and long term. The short term is defined as the period between installing the energy efficiency and adjusting the rate levels. The medium term begins once rates are adjusted and lasts until the change in energy efficiency results in an adjustment to the capital plan. The long term begins once the capital expansion plan has been changed.

Figure 3-2. Timeline of Distributional Impacts When PCT > 1 and RIM < 1



From a participant perspective, because the PCT is above 1.0, the participant is better off once an investment in energy efficiency is made, as the utility bill is lower than it would have been throughout the time horizon. In the short term, the non-participant is indifferent since rates have not been adjusted.[5] However, because the RIM is below 1.0, the utility is saving less than the drop in revenue from the participant and will therefore have lower return on equity (ROE), or debt-coverage ratio (DCR) for a public utility, compared to the case without energy efficiency. Note that for utilities with decoupling mechanisms or annual fuel cost adjustments, some or all of the rate impact may be felt before the next regular rate case cycle.

In the medium term, rates will be increased to hit the target ROE or DCR and the utility will be indifferent to the energy efficiency. This rate increase, however, affects the non-participating customers who have the same consumption as they otherwise would have, but now face higher rates. Finally, in the long term, energy efficiency may reduce the capacity needs of the system, as the capital expansion requirements of the utility are reduced. The long-term rate impact will depend on the level of fixed capital costs included in the avoided costs to value the energy savings. If the avoided costs include the long-term capacity cost savings realized through energy efficiency, a RIM ratio below 1.0 would indicate that rates will be higher in the long term. In many cases, however, avoided costs are based primarily on market prices, which tend to represent a short-term view. Thus, it may be that energy efficiency will meet load growth at a lower cost than that of alternative utility investments, and rates will be lower than they otherwise would have been even if the RIM ratio is below 1.0. To the extent that less capital is needed, earnings will be lower for the utility since the utility will be smaller relative to the no-efficiency case. However, ROE or DCR will be unchanged in the long term since rates will be adjusted periodically based on the target ROE or DCR.

3.3 Notes

[1] PM10 is particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

[2] Calculations of the cost tests were made by the paper's authors using a simplified analysis tool. This serves to illustrate the concepts, but may not match exactly what each utility has reported based on their own analysis.

[3] The inclusion of the environmental adder in the TRC is an effort to directly internalize the externalities of environmental impacts into California's primary cost test, which is the TRC (see Section 5.1.1).

[4] More detailed analysis of impacts over time can be evaluated with the National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator, using a set of assumptions that can be modified to fit a particular utility. See <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>.

[5] If the load forecasts used in rate-making are adjusted to reflect projected efficiency savings, rates may increase in the short term as well.

4: Key Drivers in the Cost-Effectiveness Calculation

In addition to the cost-effectiveness tests themselves, there are a number of choices in developing the costs and benefits that can significantly affect the cost-effectiveness results. This chapter describes some of the major choices available to analysts and policy-makers; it is a resource and reference for identifying and better understanding the variations in possible terms and approaches and developing a more robust understanding of possible evaluation techniques and their trade-offs. Because energy efficiency programs vary in different energy sectors and have different embedded savings and cost values, the variations on these terms are considerable. Thus, this chapter cannot be a step-by-step guide of all possible conditions.

Issues covered in this chapter include:

- Which benefits to include in each cost-effectiveness test.
- Whether to emphasize accuracy or transparency.
- Which methodology to use to forecast future benefits of energy and capacity savings.
- What time period to consider when assessing costs and benefits.
- Whether to determine demand- and supply-side resource requirements in the same analysis (true "integrated resource planning").
- Whether to use a public, non-proprietary data set to develop the benefits, or rely on proprietary forecasts and estimates.
- Which discount rates to use in NPV analysis.
- Whether to incorporate non-energy benefits (NEBs) and costs in the calculation.
- What NTG to use.
- Whether to include CO_2 emissions reductions in the analysis.
- Whether to include RPS procurement costs in the analysis.

Ultimately, the types of costs, benefits, and methodology used depend on the policy goals. This chapter outlines the key terms that will need to be addressed in weighing and evaluating efficiency programs. It also provides a discussion of key factors in applying cost-effectiveness test terms.

4.1 Framework for Cost-Effectiveness Evaluation

The typical approach for quantifying the benefits of energy efficiency is to forecast long-term "avoided costs," defined as costs that would have been spent if the energy efficiency savings measure had not been put in place. For example, if an electric distribution utility expects to purchase energy at a cost of $70 per megawatt-hour (MWh) on behalf of customers, then $70/MWh is the value of reduced purchases from energy efficiency. In addition, the utility may not have to purchase as much system capacity (ICAP or UCAP),[1] make as many upgrades to distribution or transmission systems, buy as many emissions offsets, or incur as many other costs. All such cost savings resulting from efficiency are directly counted as "avoided cost" benefits. In addition to the directly counted benefits, the state regulatory commission or governing councils may request that the utility account for indirect cost savings that are not priced by the market (e.g., reduced CO_2 emissions). For additional information on avoided costs, refer to the National Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b [Chapter 2]).

4.2 Choosing Which Benefits to Include

There are two main categories of avoided costs: energy-related and capacity-related avoided costs. Energy-related avoided costs involve market prices of energy, losses, natural gas commodity prices, and other benefits associated with energy production such as reduced air emissions and water usage. Capacity-related avoided costs involve infrastructure investments such as power plants, transmission and distribution lines, pipelines, and liquefied natural gas (LNG) terminals. Environmental benefits make up a third category of benefits that are frequently included in avoided costs. Saving energy reduces air emissions including GHGs, and saving capacity addresses land use and siting issues such as new transmission corridors and power plants.

Table 4-1 lists the range of avoided cost components that may be included in avoided cost benefits calculations for electricity and natural gas energy efficiency programs. The most commonly included components (and which comprise the majority of avoided costs) for electric utilities are both energy and capacity. Natural gas utilities will typically include energy and may or may not include the capacity savings.[2] Depending on the utility and the focus of the state regulatory commission or governing council, others may also be included.

Table 4-1. Universe of Energy and Capacity Benefits for Electricity and Natural Gas

Electricity Energy Efficiency	
Energy Savings	Capacity Savings
Market purchases or fuel and operation and maintenance costs	Capacity purchases or generator construction
System losses	System losses (peak load)
Ancillary services related to energy	Transmission facilities
Energy market price reductions	Distribution facilities
Co-benefits in water, natural gas, fuel oil, etc.	Ancillary services related to capacity
Air emissions	Capacity market price reductions
Hedging costs	Land use
Natural Gas Energy Efficiency	
Energy Savings	Capacity Savings
Market purchases at city gate	Extraction facilities
Losses	Pipelines
Air emissions	Cold weather action/pressurization activities
Market price reductions	Storage facilities
Co-benefits in water, natural gas, fuel oil, etc.	LNG terminals
Hedging costs	

Note: More detail on each of these components can be found in Chapter 3 of the Action Plan's *Guide to Resource Planning with Energy Efficiency* (National Action Plan for Energy Efficiency, 2007b).

Most states select a subset to analyze from within this "universe" of benefits when evaluating energy efficiency. No state considers them all. The most important factor in choosing the components is to inform the decisions on energy efficiency given the policy backdrop and situation of the state. As an example of how calculations may be adopted to specific conditions, California chose to include market price reduction effects in evaluating energy efficiency programs during the California Energy Crisis. Similarly, large capital projects such as LNG terminals or power plants, or a focus on GHGs or local environment, might lead to emphasizing these components over others. There may be diminishing value to detailed analysis of small components of the avoided cost that will not change the fundamental decisions.

4.3 Level of Complexity When Forecasting Avoided Costs

Within the avoided cost framework, there are many ways to estimate the benefits. The approach may be as simple as estimating the fixed and variable costs of displaced generation and using them as the avoided costs (as is done in Texas). An alternative approach is to use a more sophisticated integrated resource planning (IRP) approach that simultaneously evaluates both supply- and demand-side investments. This IRP analysis may include a simulation of the utility system with representation of all of the generation, transmission constraints, and loads over time (for example, see the Northwest Power Planning and Conservation Council 5th Power Plan[3] or PacifiCorp Integrated Resource Planning[4]). This requires a much more complex set of analysis tools, but provides more information on the right timing, desired quantity, and value of energy efficiency with respect to the existing utility system and its expected future loads.

In general, more sophisticated and accurate estimates of benefits are better. However, other considerations include the following:

- **Availability of resources** needed to complete the analysis and stakeholders' review before adoption may be a problem in states without intervener compensation.
- **Time taken to complete** the analysis with sophisticated IRP approaches could delay implementation of energy efficiency. The regulatory landscape in many states is littered with IRP proceedings that are contentious and have taken years to complete.
- **Transparency of the approach** to a broad set of stakeholders is also valued and may be easier to achieve without sophisticated models to achieve broader support.

4.4 Forecasts of Avoided Costs

Depending on the utility type and market structure in a region, there are a number of methodology options for developing avoided natural gas and electricity costs. The first approach is to use forward and futures market data, which are publicly available and transparent to all stakeholders. However, energy efficiency is likely to have a life longer than available market prices, and a supplemental approach will also be needed to estimate long-term costs.

The second approach is to use public or private long-run forecast of electricity and natural gas costs, such as those produced by the Department of Energy's Energy Information Agency and many state agencies (utilities participating in wholesale markets will also have proprietary forward market forecasts to inform trading activities).

The third approach is to develop simple long run estimates of future electricity value by choosing a typical "marginal resource" such as a combined cycle natural gas plant and forecasting its variable costs into the future. A more sophisticated variation would be to incorporate production simulation modeling of the electricity system into this analysis. Overall, it is important to understand the underlying assumptions of the forecasting approach and assess whether or not these assumptions are appropriate for the intended purpose. Table 4-2 summarizes avoided costs approaches by utility type and each is described in more detail below.

Table 4-2. Approaches to Valuing Avoided Energy and Capacity Costs by Utility Type

Utility Type	Near-Term Analysis (i.e., Market Data Available)	Long-Term Analysis (i.e., No Market Data Available)
Distribution electric or natural gas utility	Current forward market prices of energy and capacity	Long-term forecast of market prices of energy and capacity
Electric vertically integrated utility	Current forward market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects	Long-term forecast of market prices of energy and capacity *or* Expected production cost of electricity and value of deferring generation projects

4.4.1 Market Data

For utilities that are tightly integrated into the wholesale energy market, forward market prices provide a good basis for establishing avoided costs. If the utility is buying electricity, energy efficiency reduces the need to purchase electricity. If the utility can sell excess electricity, energy savings enables additional sales, resulting in incremental revenue. In either case, the market price is the per kWh value of energy efficiency. Forward market electricity prices are publicly available through services such as Platt's "Megawatt Daily," which surveys wholesale electricity brokers. This data is typically available extending three or four years into the future depending on the market.

The market price is also a good approach for natural gas utilities. The NYMEX futures market for natural gas provides market prices as far as 12 years in advance by month.[5] The market currently has active trading daily over the next three to five years. The NYMEX market also includes basis swaps that provide the price difference between Henry Hub and most delivery points in the United States.[6] Some analysts hesitate to use market data such as NYMEX beyond the period of active trading for fear that low volume of trading creates liquidity problems and prices that are not meaningful. While more liquid markets provide more rigor in the prices, the less liquid long-term markets are still available for trading and are therefore unbiased estimates of future market prices and may still be the best source of data.

Market prices provide a relatively simple, transparent, and readily accessible basis for quantifying avoided costs. On the other hand, market prices tend to be influenced primarily by current market conditions and variable operating costs, particularly in the near term. Market prices alone may not adequately represent long-term and/or fixed operating costs. The production simulation and proxy plant approaches described below provide alternative approaches that address long-term fixed costs.

4.4.2 Production Simulation Models

For self-resourced electric utilities that do not have wholesale market access or actively trade electricity, a "production simulation" forecast may be the best approach to forecast energy costs. A production simulation model is a software tool that performs system dispatch decisions to serve load at least cost, subject to constraints of transmission system, air permitting, and other operational parameters. The operating cost of the "marginal unit" in each hour or time period is used to establish the avoided cost of energy. The downside of production simulation models is that they are complex, rely on sophisticated algorithms that can appear as a "black box" to stakeholders, and have to be updated when market prices of inputs such as natural gas change. In addition, these types of models can have difficulty predicting market prices since the marginal energy cost is based on production cost, rather than supply and demand interactions in a competitive electricity market. If production simulation produces prices that differ from those actually seen in the market, energy efficiency can end up facing a cost hurdle that differs from the hurdles faced by supply-side resources. Long-term natural gas forecasts also often rely on production simulation to model regional supply, demand, and transportation dynamics and estimate the equilibrium market prices.

4.4.3 Long-Run Marginal Cost and the "Proxy Plant"

Developing a "proxy plant" is an alternative to production simulation approaches and may be used when market data is not available or appropriate. Under this approach, a fixed hypothetical plant is used as a proxy for the resources that will be built to meet incremental load.[7] Selecting the proxy-plant, the construction costs, financial assumptions, and operating characteristics are all assessed from its characteristics. As an example, the variable costs of a combined cycle natural gas plant may be used as a proxy for energy costs. The annual fixed cost of a combustion turbine may be used as a proxy for capacity costs. Several methods can be used to allocate fixed costs, adjust the variable operating costs, or otherwise shape the costs of the plant(s) across different time-of-use (TOU) periods. These methods include applying market price or system load shapes, loss of load probabilities, or marginal heat rates to vary prices by TOU. Another commonly used method is the peaker methodology, which uses an allocation of the capacity costs associated with peaking resources (typically combustion turbines) and the marginal system energy cost by hour (system lambda) to estimate avoided electricity costs in each hour or TOU period. These costs are then used to estimate the costs of the energy and capacity in the avoided costs calculations. The proxy plant approach is more transparent and understandable to many stakeholders (particularly in comparison to production simulation). The proxy plant approach may be used in conjunction with market data, to estimate costs for the periods beyond the time horizons when existing market data are available.

4.4.4 Proprietary and Public Forecasts

The easiest approach for a utility to develop long-term avoided costs may be to use its own internal forecast of market prices. This approach provides estimates of avoided cost that are closely linked to the utility operations. However, the methodology may be confidential since utilities involved in procuring electricity or natural gas on the market may not to reveal their expectations of future prices publicly. Therefore, the use of internal forecasts can significantly limit the stakeholder review process for evaluation of energy efficiency programs.

Public forecasts of avoided costs may also be used to develop a more open process for energy efficiency evaluation and planning. California, Texas, the Northwest Power Planning Council, Ontario, and others use a non-proprietary methodology. An open process allows non-utility stakeholders to evaluate and comment on the methodology, thereby increasing the confidence that the analysis is fair. This approach also makes it possible for energy efficiency contractors to evaluate the cost-effectiveness of proposed energy efficiency upgrades. Unfortunately, this open process may diverge from internal forecasts and introduce some discrepancy between the publicly adopted numbers and those actually used by utilities in resource planning and procurement decisions. States balance these concerns and generally commit to one path or the other.

Policy-makers may also rely on existing publicly available forecasts of electricity or natural gas. The most universal source of forecasts is the Annual Energy Outlook (AEO), provided by the Department of Energy's Energy Information Agency.[8] This public forecast provides regional long-term forecasts of electricity and natural gas. In addition to the AEO, state energy agencies or regional groups may provide their own independent forecasts, which may include sensitivity analysis. Some parties, however, view publicly developed forecasts with some skepticism, as they may be seen as being overly influenced by political considerations or the compromises necessary to gain wide support in a public process.

4.4.5 Risk Analysis

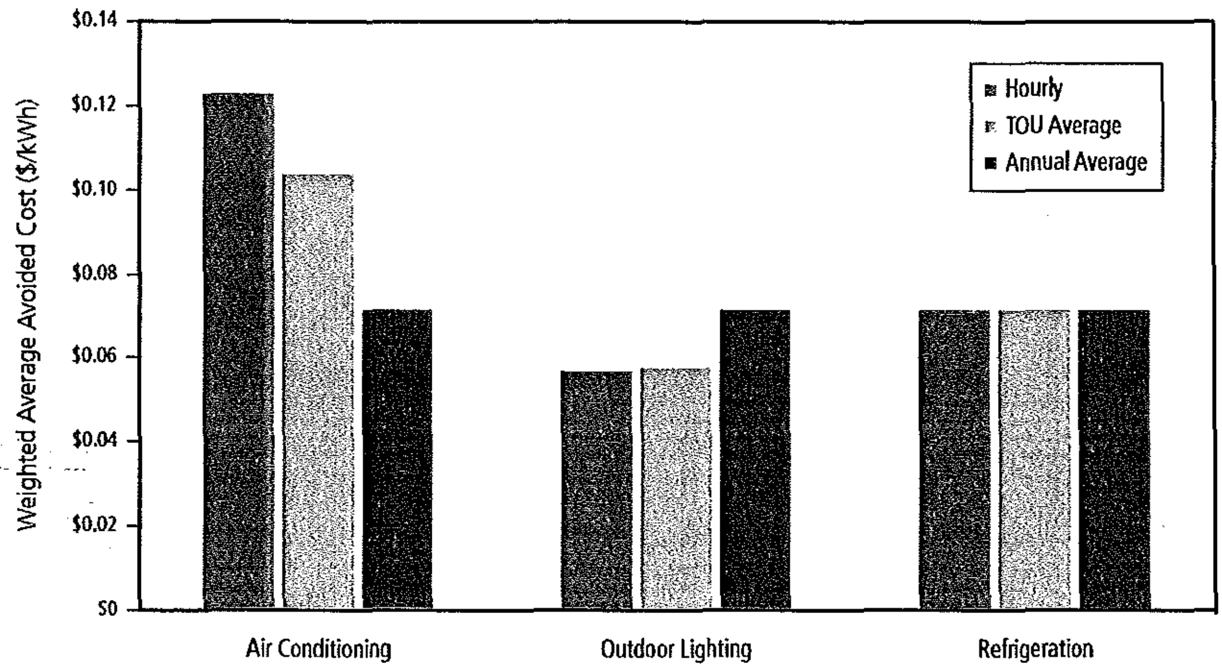
Electricity and natural gas prices are quite volatile and subject to cyclical ups and downs. In reducing load, energy efficiency also reduces a utility's exposure to fluctuating market prices. This provides an option or hedge value that can be quantified with risk analysis, but which is omitted when a single forecast of avoided costs is used.

Increasingly, utilities have used scenario and risk analysis to assess the benefits of different investment options under a range of future scenarios. One of the simpler approaches is to compare the cost-effectiveness results under multiple scenarios, using a high, expected, and low energy price forecast for example. More advanced techniques, such as Monte Carlo simulation, may be used to evaluate the performance of various resource plans under a wide range of possible outcomes.

4.5 Area- and Time-Specific Marginal Costs

For all of the forecasting approaches for avoided costs, the analyst must decide the level of disaggregation by area and time used in developing the forecasts. The marginal costs of electricity can vary significantly hour to hour and both electricity and natural gas prices vary by area and time of year. Similarly, the load reductions provided by energy efficiency measures also vary by season and time of day. Figure 4-1 shows the differences that can result when using hourly, TOU, and annual average avoided costs for different end uses, based on a study of air conditioning, outdoor lighting, and refrigeration end uses in California. The significance of using either TOU or average annual costs is highly dependent on the end use and demand/cost characteristics of the region in question. In California, the decision to use hourly avoided costs was made in order to appropriately value air conditioning energy efficiency.[9] This approach almost doubles the value of air conditioning measures relative to a flat annual average assessment of avoided cost (~$0.12/kWh vs. ~$0.07). In the case of other end uses, such as outdoor lighting efficiency, there is very little difference between hourly and TOU costs for end uses that operate evenly within a 24-hour period (e.g., refrigeration), there is no difference in method.

Figure 4-1. Implication of Time-of-Use on Avoided Costs



Source: California Proceeding on Avoided Costs of Energy Efficiency; R.04-04-025.

Another consideration of time-dependent avoided cost analysis is the need to correctly evaluate the tradeoffs between different types of energy efficiency measures. Hourly avoided costs are highly detailed, capturing the cost variance within and across major time periods. Annual average costs ignore the timing of energy savings. In the example above, using an annual average method, CFLs and outdoor lighting efficiency would receive the same value as air conditioning energy efficiency, while in actuality air conditioning energy efficiency is much more valuable to the system overall because it reduces the peak load significantly. The use of hourly avoided costs in this case reveals the large potential avoided cost value of air conditioning savings relative to other efficiency measures.

4.6 Net Present Value and Discount Rates

A significant driver of overall cost-effectiveness of energy efficiency is the discount rate assumption. Each cost-effectiveness test compares the NPV of the annual costs and benefits over the life of an efficiency measure or program. Typically, energy efficiency measures require an upfront investment, while the energy savings and maintenance costs accrue over several years. The calculation of the NPV requires a discount rate assumption, which can be different for the stakeholder perspective of each cost-effectiveness test.

As each perspective portrays a specific stakeholder's view, each perspective comes with its own discount rate. The five cost-effectiveness tests are listed in Table 4-3, along with the appropriate discount rate and an illustrative value. Using the appropriate discount rate is essential for correctly calculating the net benefits of an investment in energy efficiency.

Table 4-3. The Use of Discount Rates in Cost-Effectiveness Tests

Tests and Perspective	Discount Rate Used	Illustrative Value	Present Value of $1 a Year for 20 Years*	Today's Value of the $1 Received in Year 20
PCT	Participant's discount rate	10%	$8.51	$0.15
RIM	Utility WACC	8.5%	$9.46	$0.20
PACT	Utility WACC	8.5%	$9.46	$0.20
TRC	Utility WACC	8.5%	$9.46	$0.20
SCT	Social discount rate	5%	$12.46	$0.38

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

* This value is the same as not having to purchase $1 of electricity per year for 20 years.

Three kinds of discount rates are used, depending on which test is being calculated. For the PCT, the discount rate of an individual or business is used. For a household, this is taken to be the consumer lending rate, since this is the debt cost that a private individual would pay to finance an energy efficiency investment. It is typically the highest discount rate used in the cost-effectiveness tests. However, since there are potentially many different participants, with very different borrowing rates, it can be difficult to choose a single appropriate discount rate. Based on the current consumer loan market environment, a typical value may be in the 8 to 10 percent range (though a credit card rate might be much higher). For a business firm, the discount rate is the firm's weighted average cost of capital (WACC). In today's capital market environment, a typical value would be in the 10 to 12 percent range—though it can be as high as 20 percent, depending on the firm's credit worthiness and debt-equity structure. Businesses may also assume higher discount rates if they perceive several attractive investment opportunities as competing for their limited capital dollars. Commercial and industrial customers can have payback thresholds of two years or less, implying a discount rate well in excess of 20 percent.

For the SCT, the social discount rate is used. The social discount rate reflects the benefit to society over the long term, and takes into account the reduced risk of an investment that is spread across all of society, such as the entire state or region. This is typically the lowest discount rate. For example, California uses a 3 percent real discount rate (~5 percent nominal) in evaluating the cost-effectiveness of the Title 24 Building Standards.

Finally, for the TRC, RIM, or PACT, the utility's average cost of borrowing is typically used as the discount rate. This discount rate is typically called the WACC and takes into account the debt and equity costs and the proportion of financing obtained from each. The WACC is typically between the participant discount rate and the social discount rate. For example, California currently uses 8.6 percent in evaluating the investor-owned utility energy efficiency programs.

Using these illustrative values for each cost-effectiveness test, the third column of Table 4-3 shows the value of receiving $1 per year for 20 years from each perspective. This is analogous to the value of not having to purchase $1 of electricity per year. From a participant perspective assuming a 10 percent discount rate, this stream is worth $8.51; from a utility perspective, it is worth $9.46; and from a societal perspective, it is worth $12.46. The effect of the discount rate increases over time. The value today of the $1 received in the 20th year ranges from $0.15 from the participant perspective to $0.38 in the societal perspective, more than twice as much. Since the present value of a benefit decreases more over time with higher discount rates, the choice of discount rate has a greater impact on energy efficiency measures with longer expected useful lives.

4.7 Establishing the Net-to-Gross Ratio

A key requirement for cost benefit analysis is estimating the NTG. The NTG adjusts the cost-effectiveness results so that they only reflect those energy efficiency gains that are attributed to, and are the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings achieved as a direct result of program expenditures by removing savings that would have occurred even absent a conservation program. Establishing the NTG is critical to understanding overall program success and identifying ways to improve program performance. For more information on NTG in the context of efficiency program evaluation, see Chapter 5 of the National Action Plan for Energy Efficiency's *Model Energy Efficiency Program Impact Evaluation Guide* (National Action Plan for Energy Efficiency, 2007c).

Gross energy impacts are the changes in energy consumption and/or demand that result directly from program-related actions taken by energy consumers that are exposed to the program. Estimates of gross energy impacts always involve a comparison of changes in energy use over time among customers who installed measures versus some baseline level of usage.

Net energy impacts are the percentage of the gross energy impact that is attributable to the program. The NTG reduces gross energy savings estimates to reflect three types of adjustments:

- Deduction of energy savings that would have been achieved even without a conservation program.
- Deduction of energy savings that are not actually achieved in real world implementation.
- Addition of energy savings that occur as an indirect result of the conservation program.

Key factors addressed through the NTG are:

- **Free riders.** A number of customers take advantage of rebates or cost savings available through conservation programs even though they would have installed the efficient equipment on their own. Such customers are commonly referred to as "free riders."
- **Installation rate.** In many cases the customer does not ultimately install the equipment. In other cases, efficient equipment that is installed as part of an energy conservation program is later bypassed or removed by the customer. This is common for CFL programs.

- **Persistence/failure.** A certain percentage of installed equipment can be expected to fail or be replaced before the end of its useful life. Such early failure reduces the achieved savings as compared to pre-installation savings estimates.

- **Rebound effect.** Some conservation measures may result in savings during certain periods, but increase energy use before or after the period in which the savings occur. In addition, customers may use efficiency equipment more often due to actual or perceived savings.

- **Take-back effect.** A number of customers will use the reduction in bills/energy to increase their plug load or comfort by adjusting thermostat temperatures.

- **Spillover.** Spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program.

4.8 Codes and Standards

Another way to encourage energy efficiency is to adopt increasingly strict codes and standards for energy use in buildings and appliances. This process is occurring in parallel with energy efficiency programs in most states, as each approach has its advantages and disadvantages. Codes and standards can be adopted for the state as a whole and do not demand the same level of state or utility funding as incentive programs. They do, on the other hand, impose regulatory and compliance costs on businesses and residents. Codes and standards generally involve a more complicated and potentially contentious legislative process than utility energy efficiency programs overseen by regulatory agencies. They also present enforcement challenges; local planning departments often do not have the staff, budget, or expertise to focus on state regulations related to energy use.

Increasingly strict codes and standards effectively raise the baseline that efficiency measures are compared against over time. This will reduce the energy savings and net benefits of efficiency measures, either by reducing the estimated savings or increasing the NTG.

4.9 Non-Energy Benefits and Costs

Conservation measures often have additional benefits beyond energy savings. These benefits include improved comfort, health, convenience, and aesthetics and are often referred to as non-energy effects (to include costs as well as benefits) or NEBs. None of the five cost-effectiveness tests explicitly recognizes changes in NEBs. Unless specifically cited, databases and studies generally exclude NEBs.

Examples of NEBs include:

- **From the customer perspective,** increased comfort, air quality, and convenience. For example, a demand response event that turns off air conditioning can reduce comfort and be a "cost" to the customer. Conversely, participants who gain improved heating and insulation can experience increased comfort, gaining an overall benefit.

- **From the utility perspective,** NEBs have been shown to reduce the number of shut-off notices issued or bill complaints received, particularly in low-income communities.

- **From a societal perspective**, efficiency programs can provide regional benefits in increased community health and improved aesthetics. On a larger scale, energy efficiency also reduces reliance on imported energy sources and provides national security benefits.

Studies attempting to estimate the value of NEBs are limited. Such studies often rely on participant surveys, which are designed to indicate their willingness to pay for NEBs or comparative valuation of various NEBs. Other studies rely on statistical analysis of survey data to estimate or "reveal" participant preferences toward NEBs. Both survey and statistical methods have significant limitations, and it is difficult to account for changing preferences across different income levels, cultural backgrounds, and household types. When values are not available, the judgment of regulators or program managers may be used. Examples of accounting for NEBs include decreasing costs or increasing benefits by a fixed percentage in the cost-effectiveness tests. To date, more emphasis has been placed on including NEBs than on non-energy costs. Nevertheless, as NEBs are incorporated in cost-effectiveness evaluation, non-energy costs should be evaluated on an equivalent basis. Examples of non-energy costs include reduced convenience and increased disposal or recycling costs.

4.10 Incentive Mechanisms

An area of growing interest in the application of cost-effectiveness tests is in establishing incentive mechanisms for utility efficiency programs. There exist two natural disincentives for utilities to invest in energy efficiency programs. First, energy efficiency reduces sales, which puts upward pressure on rates and can affect utility earnings. Second, utilities make money through a return on their capital investments or rate base. The financial disincentives for utilities are discussed thoroughly in the National Action Plan for Energy Efficiency's paper *Aligning Utility Incentives with Energy Efficiency Investment* (National Action Plan for Energy Efficiency, 2007a).

To address the reduced earnings from energy efficiency, states are increasingly exploring incentive mechanisms that allow a utility to earn a return on energy efficiency expenditures similar to the return on invested capital. The intent is to give the utility an equal (or greater) financial incentive to invest in energy efficiency as compared to traditional utility infrastructure.

The cost-effectiveness test results are increasingly being used as a metric to measure the incentive payment to the utility, based on the performance of the energy efficiency program. However, as discussed previously, no single cost-effectiveness test captures all of the goals of the efficiency program. Therefore, some states, such as California, have developed "weighting" approaches that combine the results of the cost-effectiveness tests. California has established a Performance Earnings Basis that is based on two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utilities' combined results using this metric if the utilities' portfolio of savings meets or exceeds the utility commission's established energy savings goals.

When the cost-effectiveness tests are used in the payment of shareholder incentives, there will be additional scrutiny on the input assumptions and key drivers in the calculation. With this additional pressure, transparency and stakeholder review of the methodology becomes more important. Finally, the cost-effectiveness tests' use and their weights must be considered with care to align the utility objectives with the goals of the energy efficiency policy.

4.11 Greenhouse Gas Emissions

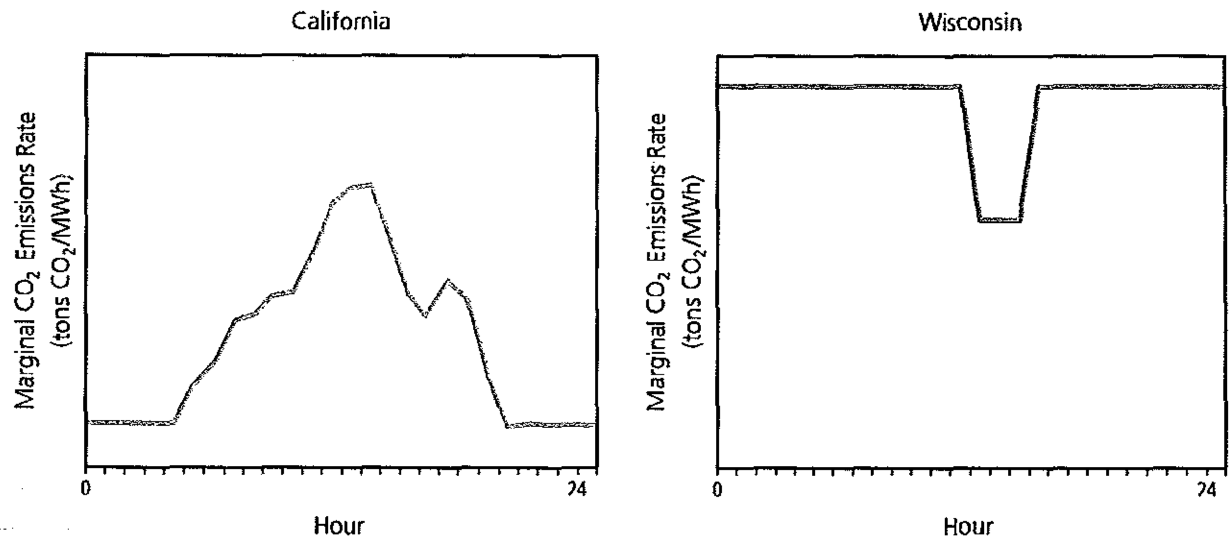
Another factor to consider when determining the cost-effectiveness of an energy efficiency program is how to value the program's effect on GHG emissions. The first step is to determine the quantity of avoided CO_2 emissions from the efficiency program. Once that quantity has been determined, its economic value can be calculated and added to the net benefits of the energy efficiency measures used to achieve the reductions. Currently, some jurisdictions use an explicit monetary CO_2 value in cost-benefit calculations, and some do not. California includes a forecast of GHG values in the avoided costs used to perform the cost-effectiveness tests and Oregon requires that future GHG compliance costs be explicitly considered in utility resource planning. Several utilities, including Idaho Power, PacifiCorp, and Public Service Company of Colorado, include GHG emissions and costs when evaluating supply- and demand-side options, including energy efficiency, in their IRP process.

The GHG emissions emitted through the end use of natural gas and heating oil are driven by the carbon content of the fuel and do not vary significantly by region or time of use. The GHG profiles of electricity generation do differ greatly by technology, fuel mix, and region. A very rough estimate of GHG emissions savings from energy efficiency can be obtained by multiplying the kWh saved by an average emission factor. Alternatively, it can be estimated based upon a weighted average of the heat rates and emission factors for the different types of generators in a utility's generation mix. Such "back of the envelope" methods are useful for agency staff and others who wish to quickly check that results from more sophisticated methods are approximately accurate.

A formal cost-effectiveness evaluation uses marginal emission rates that more accurately reflect the change in emissions due to energy efficiency and have an hourly profile that varies by region. For states in which natural gas is both a base load and peaking fuel, marginal emissions will be higher during peak hours because of the lower thermal efficiency of peaking plants, and therefore energy efficiency measures that focus their kWh savings on-peak will have the highest avoided GHG emissions per kWh saved. However, in states in which coal is the dominant fuel, off-peak marginal emission rates may actually be higher than on-peak if the off-peak generation is coal and on-peak generation is natural gas. Figure 4-2 illustrates this difference, comparing reported marginal emission rates for California and Wisconsin.

To date, monetary values for GHG emissions have been drawn primarily from studies and journal articles and applied in regulatory programs. While there is widespread agreement that GHG reduction policies are likely to impose some cost on CO_2 emissions, achieving consensus on a specific $/ton price for the electricity sector is challenging. As Congress and individual states consider specific GHG legislation, a number of the policy considerations that will affect the CO_2 price remain in flux.

Figure 4-2. Comparison of Marginal CO_2 Emission Rates for a Summer Day in California and Wisconsin



Source: Erickson et al. (2004).

Note: The on-peak marginal emissions rate of each state is set by natural gas peaking units. The off-peak rates are quite different, reflecting the dominance of coal base load generation in Wisconsin and natural gas combined cycle in California.

4.12 Renewable Portfolio Standards

An emerging topic in energy efficiency cost-effectiveness is how to treat the interdependence between energy efficiency and RPS. RPS goals are typically established state by state as a percentage of retail loads in a future target year (e.g., 20 percent renewable energy purchases by 2020). Unlike supply-side investments, energy efficiency, by reducing load, can reduce the amount of renewable energy that must be procured pursuant to RPS targets, thereby reducing RPS compliance cost.

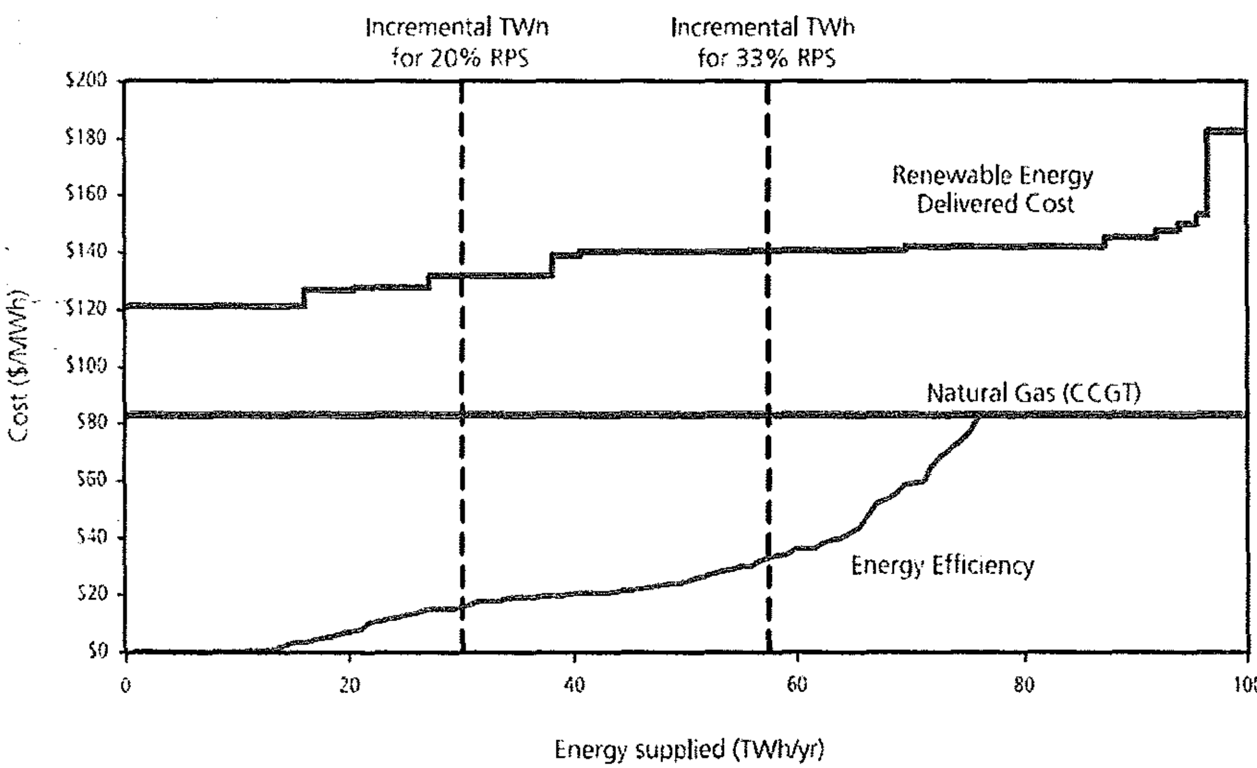
Some renewable technologies can provide energy at costs close to that of conventional generation. However, for many states, the marginal cost of complying with state RPS goals will be set either by more expensive technologies or by distant resources with significant transmission costs. When the cost of renewable energy needed to meet RPS goals is significantly higher than the avoided cost for conventional generation, energy efficiency provides additional savings by reducing RPS compliance costs.

The additional RPS-related savings from energy efficiency for California are illustrated in Figure 4-3. In California, as in many regions, the least-cost conventional base-load resource is combined cycle gas turbine (CCGT), shown here with a cost of $82/MWh. The avoided costs against which energy efficiency has historically been evaluated are based on such conventional generation. This has limited the promotion of energy efficiency to technologies with costs below $80/MWh. In practice, given limited budgets and staff, utilities have focused primarily on technologies with costs of $40/MWh or below.

In comparison, the estimated cost of renewable energy needed to meet California's 20 percent RPS standard is over $130/MWh. So for every 1,000 MWh saved by energy efficiency, the utilities avoid the purchase 800 MWh of conventional generation at $82/MWh and 200 MWh of renewable generation at $130/MWh. Thus the RPS standard increases the cost of avoided energy purchases from $82/MWh to $92/MWh ($82/MWh + [130/MWh - $82/MWh] × 20%).

Utilities in California have begun to incorporate the higher cost of renewable generation in their internal evaluation of load reduction strategies. However, as in most jurisdictions, the cost of meeting RPS targets has not yet been formally included in the adopted avoided cost forecasts against which energy efficiency programs are officially evaluated.

Figure 4-3. Natural Gas, Energy Efficiency, and Renewable Supply Curves for California



Source: Mahone et al. (2008).

4.13 Defining Incremental Cost

In order to apply the avoided cost approach in evaluating benefits of energy efficiency cost-effectiveness, the analyst must also determine the incremental cost of the measures. Energy efficiency portfolio costs are easier to evaluate than benefits, since they are directly observable and auditable. For example, marketing costs, measurement and evaluation costs, incentive costs, and administration costs all have established budgets. The exception to this is in estimating the incremental measure cost. This is a necessary input for the TRC, SCT, and PCT calculations.

For each of these tests, the appropriate cost to use is the cost of the energy efficiency device in excess of what the customer would otherwise have made. Therefore, the incremental measure costs must be evaluated with respect to a baseline. For example, a program that provides an incentive to a customer to upgrade to a high-efficiency refrigerator would use the premium of that refrigerator over the base model that would otherwise have been purchased.

Establishing the appropriate baseline depends on the type of measure. In cases where the customer would not have otherwise made a purchase, for example the early replacement of a working refrigerator, the appropriate baseline is zero expenditure.[10] In this case, the incremental cost is the full cost of the new high-efficiency unit. The four basic measure decision types are described in Table 4-4 along with different names often used for each decision type.

Table 4-4. Defining Customer Decision Types Targeted by Energy Efficiency Measures

Decision Type	Definition	Example
New New construction Lost opportunity	Encourages builders and developers to install energy efficiency measures that go above and beyond building standards at the time of construction	Utility offers certification or award to builder of new homes that meet or exceed targets for the efficient use of energy.
Replacement Failure replacement Natural replacement Replace on burnout	Customer is in the market for a new appliance because their existing appliance has worn out or otherwise needs replacing. Measure encourages customer to purchase and install efficient instead of standard appliance.	The utility provides a rebate that encourages the customer to purchase a more expensive, but more efficient and longer-lasting CFL bulb instead of an incandescent bulb.
Retrofit Early replacement	Customer's existing appliance is working with several years of useful life remaining. Measure encourages customer to replace and dispose of old appliance with a new, more efficient one.	The utility provides a rebate toward the purchase of a new, more efficient refrigerator upon the removal of an older, but still working refrigerator.
Retire	Customer is encouraged to remove, but not replace existing fixture.	The utility pays for the removal and disposal of older but still working "second" refrigerators (e.g., in the garage) that customer can conveniently do without.

Table 4-5 summarizes the calculation of measure costs for each of the decision types described above. In the table, "efficient device" refers to the equipment that replaces an existing, less-efficient piece of equipment. "Standard device" refers to the equipment that would be used in industry standard practice to replace an existing device. "Old device" refers to the existing equipment to be replaced.

Table 4-5. Defining Costs and Impacts of Energy Efficiency Measures

Type of Measure	Measure Cost ($/Unit)	Impact Measurement (kWh/Unit and kW/Unit)
New New construction Lost opportunity	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Replacement Failure replacement Natural replacement Replace on burnout	Cost of efficient device **minus** cost of standard device *(Incremental)*	Consumption of standard device **minus** consumption of efficient device
Retrofit Early replacement *(Simple)*	Cost of efficient device **plus** installation costs *(Full)*	Consumption of old device **minus** consumption of efficient device
Retrofit Early replacement *(Advanced)**	Cost of efficient device **minus** cost of standard device **plus** remaining present value	*During remaining life of old device:* Consumption of old device **minus** consumption of efficient device *After remaining life of old device:* Consumption of standard device **minus** consumption of efficient device
Retire	Cost of removing old device	Consumption of old device

* The advanced retrofit case is essentially a combination of the simple retrofit treatment (for the time period during which the existing measure would have otherwise remained in service) and the failure replacement treatment for the years after the existing device would have been replaced. "Present Value" indicates that the early replacement costs should be discounted to reflect the time value of money associated with the installation of the efficient device compared to the installation of the standard device that would have occurred at a later date.

4.14 Notes

1 Installed capacity (ICAP), or unforced capacity (UCAP) in some markets, is an obligation of the electric utility (load serving entity, or LSE) to purchase sufficient capacity to maintain system reliability. The amount of ICAP an LSE must typically procure is equal to its forecasted peak load plus a reserve margin. Therefore, reduction in peak load due to energy efficiency reduces the ICAP obligation.

2 The ability to store natural gas, and to manage the gas system to serve peak demand periods by varying the pressure, reduces the share of gas costs associated with capacity relative to electricity.

3 See <http://www.nwcouncil.org/energy/powerplan/5/Default.htm>.

4 See <http://www.pacificorp.com/Navigation/Navigation23807.html>.

5 See <http://www.nymex.com/ng_fut_csf.aspx> for current market prices at Henry Hub.

6 See <http://www.nymex.com/cp_produc.aspx> for available basis swap products.

7 The specifications may be developed by the utility or developed through a regulatory process with stakeholder input.

8 Forecasts are available at <res://ieframe.dll/tabswelcome.htm>.
See <http://www.eia.doe.gov/oiaf/aeo/> for the latest edition of the Annual Energy Outlook.

9 See <http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf> for a detailed description of the development of avoided costs in California.

10 A simplifying assumption of zero as the baseline expenditure is often used, even though the equipment may have a limited remaining useful life and need replacement in a few years. Table 4-5 presents a more detailed calculation that can be used for early replacement programs.

Appendix B

5: Guidelines for Policy-Makers

A common misperception is that there is a "best" perspective for evaluating the cost-effectiveness of energy efficiency. On the contrary, no single test is more or less appropriate for a given jurisdiction. A useful analogy for the value of the five cost-effectiveness tests is the way doctors use multiple diagnostics to assess the overall health of a patient: each test reflects different aspects of the patient's health. This chapter describes how individual states use each of the five cost-effectiveness tests and why states might choose to emphasize some tests over others. Four hypothetical situations are presented to illustrate how states may emphasize particular tests in pursuit of specific policy goals.

5.1 Emphasizing Cost-Effectiveness Tests

Nationwide, the most common primary measurement of energy efficiency cost-effectiveness is the TRC, followed closely by the SCT. A positive TRC result indicates that the program will, over its lifetime, produce a net reduction in energy costs in the utility service territory. A positive SCT result indicates that the region (the utility, the state, or the United States) will be better off on the whole. Table 5-1 shows the distribution of primary cost-effectiveness tests used by state.

Table 5-1. Primary Cost-Effectiveness Test Used by Different States

PCT	PACT	RIM	TRC	SCT	Unspecified
	CT, TX, UT	FL	CA, MA, MO, NH, NM,	AZ, ME, MN, VT, WI	AR, CO, DC, DE, GA, HI, IA, ID, IL, IN, KS, KY, MD, MT, NC, ND, NJ, NV, OK, OR, PA, RI, SC, VA, WA, WY

Source: Regulatory Assistance Project (RAP) analysis.

Cost-effectiveness overall as analyzed by the TRC and SCT is not necessarily the only important aspect to evaluate when designing an energy efficiency portfolio. Even if benefits outweigh costs, some stakeholders can be net winners and others net losers. Therefore, many states also include one or more of the distributional tests to evaluate cost-effectiveness from individual vantage points. Using the results of the distribution tests, the energy efficiency measures and programs offered, their incentive levels, and other elements in the portfolio design can be balanced to provide a reasonable distribution of costs and benefits among stakeholders. Table 5-2 shows the distribution of cost-effectiveness tests used by states for either the primary or secondary consideration.

Table 5-2. Cost-Effectiveness Tests in Use by Different States as Primary or Secondary Consideration

PCT	PACT	RIM	TRC	SCT
AR, FL, GA, HI, IA, IN, MN, VA	AT, CA, CT, HI, IA, IN, MN, NO, NV, OR, UT, VA, TX	AR, DC, FL, GA, HI, IA, IN, KS, MN, NH, VA	AR, CA, CO, CT, DE, FL, GA, HI, IL, IN, KS, MA, MN, MO, MT, NH, NM, NY, UT, VA	AZ, CO, GA, HI, IA, IN, MW, MN, MT, NV, OR, VA, VT, WI

Source: Regulatory Assistance Project (RAP) analysis.

Using the PCT. The PCT provides two key pieces of information helpful in program design: at the measure level it provides some sense of the potential adoption rate, and it can help in setting the appropriate incentive level so as not to provide too small or too unnecessarily large an incentive. Setting the incentive levels is part art and part science. The goal is to get the most participation with the least cost. There is a balance between the PCT results with the PACT and RIM results. The higher the incentive, the higher the PCT benefit cost ratio and the lower the PACT and RIM benefit-cost ratio.

> "You get what you measure"
>
> When selecting cost-effectiveness tests to use as metrics for portfolio, remember the saying, "you get what you measure." If a single distributional test is used as a primary cost-effectiveness test, the portfolio may not balance benefits and costs between stakeholders. This is particularly true as utility incentive mechanisms are introduced that rely on cost-effectiveness results. Overall the results of all five cost tests provide a more comprehensive picture than any one test alone.

Using the PACT. The PACT provides an indication of how the energy efficiency program compares with supply-side investments. This is used to balance the incentive levels with the PCT. A poor PACT may also result from a low NTG, if, for example, a large number of customers would make the efficiency investment without the program. A poor PACT might also suggest that large incentives are required to induce sufficient adoption of a particular measure.

Using the RIM. The RIM as a primary consideration test is not as common as the other two distributional tests. If used, it is typically a secondary consideration test done on a portfolio basis to evaluate relative impacts of the overall energy efficiency program on rates. The results will provide a high-level understanding of the likely pressure on rates attributable to the energy efficiency portfolio. A RIM value below 1.0 can be acceptable if a state chooses to accept the rate effect in exchange for resource and other benefits. Efficiency measures with a RIM value below 1.0 can nevertheless represent the least-cost resource for a utility, depending on the time period and long-term fixed costs included in the avoided costs.

5.1.1 Use of Cost-Effectiveness Tests by State

Table 5-3 shows how states use cost-effectiveness tests. Many states use multiple cost-effectiveness tests to provide a more complete picture of energy efficiency cost-effectiveness. Eighteen states use two or more cost-effectiveness tests for some aspect of efficiency evaluation; four of those require all five tests. For example, Hawaii requires that all five tests be included in the analysis of supply and demand options in utility IRPs. Indiana uses all five tests to screen demand-side management (DSM) programs. Minnesota uses all five tests, but considers the SCT to be the most important. Many other states use two or three tests with different weights assigned to each test, or with separate tests being used for separate parts of the process. Several states have adopted formal and in some cases unique modifications to the standard forms of the tests.

The choice of tests and their applications reveal the priorities of the states and the perspectives of their regulatory commissions—the extent to which energy efficiency is considered a resource or the extent to which rates dominate policy implementation of energy efficiency. Some commissions like having a clear formula, using only one or two tests with threshold values to establish program scope.

The following are several examples of the types of decisions regulatory commissions have made regarding cost-effectiveness tests:

- In Colorado, a 2004 settlement with Xcel Energy required the TRC. A 2007 statute requires the use of a variation of the SCT that includes the utility's avoided costs, the valuation of avoided emissions, and NEBs as determined by the regulatory commission.
- Connecticut uses the PACT to screen individual DSM programs and the TRC to evaluate the total benefit of conservation and load management programs and to determine performance incentives.
- In the District of Columbia, the RIM is used for DSM programs. Those which have a cost-benefit ratio of 0.8 and 1.0 may be evaluated for other benefits, including long-term savings, market transformation, peak savings, and societal benefits.
- Iowa requires utilities to analyze DSM programs using the SCT, RIM, PACT, and PCT. According to statute, if the utility uses a test other than the SCT to determine the cost-effectiveness of energy efficiency programs and plans, it must describe and justify its use of the alternative test.
- In Montana, the SCT and TRC are used for the traditionally regulated utility that prepares IRPs. Neither test is required for the utility that conducts portfolio management, although statute specifies that the RIM should not be used.
- Utah requires that DSM programs meet the TRC and PACT in IRP. For supply and demand resources, the primary test is the PACT, calculated under a variety of scenarios; other tests may also be considered.
- California weighs the results of two of the cost-effectiveness tests, TRC and PACT, in this program screening process. California adopted a "Dual-Test" that uses the PACT to ensure that utilities are not over spending on incentives for programs that pass the TRC. The recently adopted shareholder incentive mechanisms use a weighting of two-thirds of the TRC portfolio net benefits result and one-third of the PACT portfolio net benefits result. An incentive is then paid based on the utility's combined results using this metric if the utility's portfolio of savings meets or exceeds the Commission's established energy savings goals.

Table 5-3. Use of Cost-Effectiveness Tests by States

State	Requires All	Primary Test	TRC	SCT	PCT	PACT	RIM	Other	Non-Specific
AK									•
AL									•
AR			•		•	•	•		
AZ*		SCT		•					
CA		TRC	•			•			
CO			•	•					
CT		PACT	•			•			
DC							•	•	
DE*			•						
FL		RIM	•		•		•		
GA			•	•	•		•		
HI	•		•	•	•	•	•		
IA				•	•	•	•		
ID†			•	•	•	•			
IL			•						
IN	•		•	•	•	•	•		
KS*			•				•		
KY									•
LA									•
MA		TRC	•						
MD*									•
ME		SCT		•					
MI									•
MN	•	SCT	•	•	•	•	•		
MO		TRC	•			•			
MS									•
MT			•	•					
NC									•
ND									•
NE									•
NH		TRC	•				•		
NJ								•	
NM		TRC	•						
NV				•		•		•	
NY		TRC	•						
OH									•
OK									•
OR*				•		•			
PA									•
RI								•	
SC									•
SD									•
UT		PACT	•			•			
VA	•		•	•	•	•	•		
VT		SCT		•					
TN									•
TX		PACT				•			
WA								•	
WI		SCT		•					
WV									•
WY									•

* Proposed or not yet codified in statute/Commission Order

† Allows any or all tests, though the RIM may not be used as primary or limiting cost-effectiveness test

Source: Regulatory Assistance Project (RAP) analysis.

5.2 Picking Appropriate Costs, Benefits, and Methodology

With the cost-effectiveness tests determined, it is equally important to pick the appropriate costs, benefits, and methodology to align the energy efficiency portfolio with the overall policy goals and context for energy efficiency. The choices should ultimately reflect the situation of the utility and the state, its history in implementing energy efficiency, and other considerations. To provide some guidance, four hypothetical situations are considered along with several recommendations of possible approaches in each situation. Since the hypothetical situations do not consider any specific state, they should be viewed as a starting point for discussion and not specific policy recommendation for every context.

5.2.1 Situation A: Peak Load Growth and Upcoming Capital Investments

States or regions that are experiencing high peak load growth and associated large capital investments will want to ensure that the energy efficiency portfolio appropriately targets the peak and also provides higher benefits for peak load reduction that can be used to justify higher-cost energy efficiency such as air conditioner incentives or demand response.

One approach is to introduce time-specific avoided costs by hour, or by TOU. In addition, it will be important to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side capital investments. Unless the two processes are linked in some way, the energy efficiency program may be successful in reducing peak loads only to find that the capital projects also built. This could create a situation with too much capacity, and overspending on peak load reductions. In order to coordinate demand- and supply-side planning, it is important to start early. The lead time for large supply-side projects can be five or even 10 years. In addition, it is much easier to defer or eliminate the need for the project before the supply-side project proponents are deeply vested in its outcome.

5.2.2 Situation B: Utility Financial Problems

In a situation with a utility with financial problems, due to low load growth and/or a rate freeze, a different set of energy efficiency policies might be considered. Though the problem probably cannot be fixed with energy efficiency program design, there is no need to make it worse.

There are several approaches to encourage energy efficiency without straining the utility financially. One approach is to introduce decoupling or another automatic rate adjustment for reduced sales from energy efficiency to ensure recovery of fixed costs that have already been allowed in a prior rate case. A rate adjustment, whether tied to decoupling or not, may also help improve the utility financial situation.

If rate adjustments are not possible (whether through direct adjustment, decoupling, or another approach), another option may be to limit the impact of energy efficiency by specifying a minimum portfolio RIM. This will reduce the level of energy that can be saved but allow the portfolio to continue, perhaps with some lower-scoring programs placed on hiatus, while the financial issues of the utility are addressed.

5.2.3 Situation C: Targeting Load Pockets

If a utility has areas of growing load that require new transmission and/or generation investments to be made, energy efficiency may provide an alternative. In this case, it may be less expensive to use energy efficiency and demand response to reduce peak loads than to build new supply-side infrastructure. Using demand-side resources to alleviate a load pocket also has a lower impact on the environment.

In order to target the load pockets, the energy efficiency portfolio should include programs that specifically target peak load reduction in these areas. This can be done by increasing marketing of the same programs used service-territory-wide, or by developing a specific program to target peak load reductions in an area. Area- and time-specific costing should be introduced to estimate the value of the peak load reductions. Energy efficiency program managers should be given the authority to target certain areas. In this case, the equity of providing all of the same measures service-territory-wide may be overshadowed by value of a targeted program.

Targeting marketing and implementation is, by definition, discriminatory, but for legitimate, cost-based reasons. Targeting efficiency for areas with capacity constraints can be a prudent and least-cost means of accommodating load growth or meeting reliability criteria. While they may appear to favor certain customers, targeted efforts can provide sufficient incremental value to offer net benefits for all customers.

As in Situation A, it will be important in Situation B to initiate system planning studies that integrate supply- and demand-side planning so that the energy efficiency programs have the opportunity to defer or delay the supply-side load pocket mitigation measures.

5.2.4 Situation D: Aggressive Greenhouse Gas and RPS Policies

Many states are introducing the RPS and beginning to implement aggressive GHG policies. In these situations, policy-makers will need to emphasize energy savings. One approach to consider is to focus on the TRC or SCT, and not to use the RIM results. Policy-makers might also consider including a forecast of avoided CO_2 reductions in the avoided costs. In addition, including the avoided costs of the renewable energy or low-carbon resource that would otherwise be purchased (nuclear, renewables, carbon-capture, and sequestration) as the marginal resource can increase the avoided costs. This raises the quantity of efficiency measures and programs considered cost-effective. Finally, policy-makers will want to focus the cost-effectiveness tests at the portfolio level, rather than at the program or measure level.

6: Detailed Cost-Effectiveness Test Comparison—How Is Each Cost-Effectiveness Test Used?

This chapter describes the cost-effectiveness tests in order to provide greater understanding of calculation, results, and appropriate use of each test. Information is provided on the perspective, purpose, costs, benefits, and other considerations for each of the cost-effectiveness tests.

6.1 Participant Cost Test

The PCT examines the costs and benefits from the perspective of the customer installing the energy efficiency measure (homeowner, business, etc.). Costs include the incremental costs of purchasing and installing the efficient equipment, above the cost of standard equipment, that are borne by the customer. The benefits include bill savings realized to the customer through reduced energy consumption and the incentives received by the customer, including any applicable tax credits. Table 6-1 outlines the benefits and costs included in the PCT. In some cases the NPV of incremental operations and maintenance costs (or savings) may also be included.

Table 6-1. Benefits and Costs Included in the Participant Cost Test

Benefits and Costs from the Perspective of the Customer Installing the Measure	
Benefits	Costs
• Incentive payments • Bill savings realized • Applicable tax credits or incentives	• Incremental equipment costs • Incremental installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The primary use of the PCT is to assess the appeal of an energy efficiency measure to potential participants. The higher the PCT, the stronger the economic incentive to participate. The PCT functions similarly to a simple payback calculation, which determines how many years it takes to recover the costs of purchasing and installing a device through bill savings. A cost-effective measure will have a high PCT (above 1) and a low payback period. The PCT also provides useful information for designing appropriate customer incentive levels. A high incentive level will produce a high PCT benefit-cost ratio, but reduce the PACT and RIM results. This is because incentives given to customers are seen as "costs" to the utility. The PCT, PACT, and RIM register incentive payments in different ways based on their perspective. Utilities must balance the participant payback with the goal of also minimizing costs to the utility and ratepayers.

A positive PCT (above 1) shows that energy efficiency provides net savings for the customer over the expected useful life of the efficiency measure.

6.1.1 Additional Considerations

As a measure of payback period or economic appeal, the PCT reflects an important aspect of potential participation rates. However, it is not a comprehensive evaluation of all the determinants that influence customer participation. For example, the PCT does not consider the level of marketing and outreach efforts (or expenditures) to promote the program, and marketing can be a major driver of adoption rates. In addition, new technologies may have high upfront costs, or steep learning curves, which yield limited adoption despite high PCT ratios. As a key example, energy-efficient CFLs generally reach a plateau despite high cost-effectiveness, indicating the importance of other factors in behavior besides bill savings.[1] This can be due to several factors including customer resistance and limited availability of premium features, such as the ability to dim.

Ideally the PCT will be performed using the marginal retail rate avoided by the customer. In practice the PCT is often performed using the utility's average rates for an applicable customer class. With tiered and TOU rates, the marginal rate paid by individual customers can vary significantly, which makes the use of marginal rate savings in the PCT somewhat more difficult. Furthermore, the impact of energy efficiency on a customer's peak load is difficult to predict, making changes in customer demand charges hard to estimate. In practice, the level of effort required to estimate the customers' actual savings given their consumption profile and applicable rate schedule is significant. Often utilities find it is not worth the effort at the program design or evaluation level, though it may be useful for individual customer audits. Thus the PCT gives an indication of the direct cost-based incentives for customers to participate in a given energy-efficiency program.

6.2 Program Administrator Cost Test

The PACT examines the costs and benefits of the energy efficiency program from the perspective of the entity implementing the program (utility, government agency, nonprofit, or other third party). The costs included in the PACT include overhead and incentive costs. Overhead costs are administration, marketing, research and development, evaluation, and measurement and verification.[2] Incentive costs are payments made to the customers to offset purchase or installations costs (mentioned earlier in the PCT as benefits).[3] The benefits from the utility perspective are the savings derived from not delivering the energy to customers. Depending on the jurisdiction and type of utility, the "avoided costs" can include reduced wholesale electricity or natural gas purchases, generation costs, power plant construction, transmission and distribution facilities, ancillary service and system operating costs, and other components.[4] These elements are discussed in more detail in Chapter 4. The benefits and costs included in the PACT are summarized in Table 6-2.

Table 6-2. Benefits and Costs Included in the Program Administrator Test

Benefits and Costs to the Utility, Government Agency, or Third Party Implementing the Program	
Benefits	**Costs**
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects

The PACT allows utilities to evaluate costs and benefits of energy efficiency programs (and/or demand response and distributed generation) on a comparable basis with supply-side investments. A positive PACT indicates that energy efficiency programs are lower-cost approaches to meeting load growth than wholesale energy purchases and new generation resources (including delivery and system costs). States with large needs for new supply resources may emphasize the PACT to build efficiency alternatives into procurement planning.[5]

> A positive PACT indicates that the total costs to save energy are less than the costs of the utility delivering the same power. A positive PACT also shows that customer average bills will eventually go down if efficiency is implemented.

6.2.1 Additional Considerations

The PACT provides an estimate of energy efficiency costs as a utility resource. Even the most comprehensive avoided cost estimates cannot capture all of the attributes of energy valued by the utility. In addition, the PACT only includes the program administrator costs and not those costs borne by customers. Therefore the PACT may not be seen as sufficiently comprehensive as a primary determinant of cost-effectiveness.

As with all of the cost-effectiveness tests, there are simplifications made in the calculation that should be understood when they are applied. For example, the PACT does not incorporate the different regulatory and financial treatment of utility investments in energy efficiency versus utility infrastructure. Therefore, while the PACT provides an estimate of energy efficiency as a resource, a positive PACT result does not imply that a utility will be better off financially. Finally, in order to get meaningful results on the PACT, care must be taken to estimate the actual resource savings to the utility from the energy efficiency program, including the timing and certainty of load reductions and the resulting impact on the utility supply costs.

Since the PACT includes the full savings to the utility but not the full costs of purchasing and installing the energy efficiency measures (which are paid by participants), the PACT is usually the easiest cost-effectiveness test to pass. In the SCE program featured in Appendix C, for example, the PACT ratio is 9.9—a higher value than that produced by any other cost-effectiveness test.

Jurisdictions seeking to increase efficiency implementation may choose to emphasize the PACT, which compares energy efficiency as a utility investment on par with other resources. Because the PACT includes only utility costs (and not customer contributions), the PACT is often the most permissive (and most positive) cost-effectiveness test.

6.3 Ratepayer Impact Measure

The RIM examines the impact of energy efficiency programs on utility rates. Unlike typical supply-side investments, energy efficiency programs reduce energy sales. Reduced energy sales can lower revenues and put upward pressure on retail rates as the remaining fixed costs are spread over fewer kWh. The costs included in the RIM are program overhead and incentive payments and the cost of lost revenues due to reduced sales.[6] The benefits included in the RIM are the avoided costs of energy saved through the efficiency measure (same as the PACT). Table 6-3 outlines the benefits and costs included in the RIM.

Table 6-3. Benefits and Costs Included in the Rate Impact Measure Test

Benefits and Costs to Ratepayers Overall; Would Rates Need to Increase?	
Benefits	**Costs**
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Note: The PACT and the RIM use the same benefits.

The RIM also gives an indication of the distributional impacts of efficiency programs on non-participants. Participants may see net benefits (by lowering their bills through reduced energy consumption) while non-participating customers may experience rate increases due to the same programs. As the impacts on non-participating customers depend on many factors including the timing of adjustments to rates, the RIM is only an approximation of these impacts.

The RIM answers the question, "All other things being equal, what is the impact of the energy efficiency program on utility rates if they were to be adjusted to account for the program?" A negative RIM implies that rates would need to increase for the utility to achieve the same level of earnings in the short term.[7]

In the vast majority of cases, the RIM is negative since the retail rate is typically higher than the utility's avoided cost. The RIM may be negative, even at the same time as average bills decrease (as evaluated using the PACT). Therefore, policy-makers have to decide whether to emphasize customer bills by using the PACT or customer rates by using the RIM.[8] The main reason cited for use of the RIM is to protect customer classes. Chapter 2 of the National Action Plan for Energy Efficiency Report (National Action Plan for Energy Efficiency, 2006) suggests effective ways to protect customer groups from rate increases in the rate design process that do not limit the use of energy efficiency. As described in Section 5.1 above, most jurisdictions do not choose the RIM as a primary test; many use it as a secondary consideration, if at all.[9]

6.3.1 Additional Considerations

It is sometimes observed that even least-cost utility investments made to maintain reliability often lead to a rate increase, yet the RIM has not been applied to these initiatives. One key consideration in assessing the RIM is that there is typically an allocation of fixed costs in the variable $/kWh rate. The fixed costs included in rates reflect the utility's existing revenue requirement and do not necessarily reflect future capital costs avoided through energy efficiency. Customers are often resistant to high fixed charges and lumpy utility investments are not always considered avoidable through efficiency savings that are realized gradually over time. In addition, avoided costs are often based on market prices, which tend to emphasize variable and short-term as opposed to long-term costs. Because many utilities have multiple standard, tiered, and TOU rate options, the actual marginal revenue loses to the utility can be difficult to estimate and not accurately captured when customer class average rates are used in the RIM calculation. Other considerations in the RIM, including the relationship to utility financial health over time and capacity-focused programs that yield higher RIM results, are discussed in further detail in Section 3.2.2 above.

> The RIM is the most restrictive of the five cost-effectiveness tests. When the utility's retail rates are higher than its avoided costs, the RIM will almost always be negative. Thus policy-makers may choose to emphasize the PACT and use the RIM as a secondary consideration for balancing the distribution of rate impacts.

6.4 Total Resource Cost Test

The TRC measures the net benefits of the energy efficiency program for the region as a whole. Costs included in the TRC are costs to purchase and install the energy efficiency measure and overhead costs of running the energy efficiency program. The benefits included are the avoided costs of energy (as with the PACT and the RIM). Table 6-4 outlines the benefits and costs in the TRC.

Table 6-4. Benefits and Costs Included in the Total Resource Cost Test

Benefits and Costs from the Perspective of All Utility Customers (Participants and Non-Participants) in the Utility Service Territory	
Benefits	**Costs**
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (e.g., gas and water if utility is electric) • Monetized environmental and non-energy benefits (see Section 4.9) • Applicable tax credits (see text)	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

The primary purpose of the TRC is to evaluate the net benefits of energy efficiency measures to the region as a whole. Unlike the tests describe above, the TRC does not take the view of individual stakeholders. It does not include bill savings and incentive payments, as they yield an intra-regional transfer of zero ("benefits" to customers and "costs" to the utility that cancel each other on a regional level). For some utilities, the region considered may be limited strictly to its own service territory, ignoring benefits (and costs) to neighboring areas (a distribution-only utility may, for example, consider only the impacts to its distribution system). In other cases, the region is defined as the state as a whole, allowing the TRC to include benefits to other stakeholders (e.g., other utilities, water utilities, local communities). The TRC is useful for jurisdictions wishing to value energy efficiency as a resource not just for the utility, but for the entire region. Thus the TRC is often the primary test considered by those states seeking to include the benefits not just to the utility and its ratepayers, but to other constituents as well. The TRC may be considered the sum of the PCT and RIM, that is, the participant and non-participant cost-effectiveness tests. The TRC is also useful when energy efficiency might fall through the cracks taken from the perspective of individual stakeholders, but would yield benefits on a wider regional level.[10]

The inclusion of tax credits or incentives depends to some extent on the region considered. A municipal utility might consider state and federal tax incentives as a benefit from outside the region defined for the TRC. For a utility with a service territory that includes all or most of a particular state, state tax incentives would be an intra-regional transfer that is not included in the TRC. Some jurisdictions chose to consider all tax incentives as transfers excluded from the TRC. Generally speaking, tax incentives in the TRC should be treated consistently with the other resources to which energy efficiency may be compared.

> The TRC shows the net benefits of the energy efficiency program as a whole. It can be used to evaluate energy efficiency alongside other regional resources and communicate with other planning agencies and constituencies.

6.4.1 Additional Considerations

The TRC is similar to the PACT except that it considers the cost of the measure itself rather than the incentive paid by the utility. Because the incentives are less than the cost of the measure in most cases, the TRC is usually lower than the PACT. Therefore, the TRC will be a more restrictive test than the PACT and fewer measures will pass the TRC. Indeed, it is not unusual for a measure to fail the TRC while appearing economical both to the utility (PACT) and to the participant (PCT). Due to the incentives paid by the utility, the participant and the utility each pay only a portion of the full incremental cost of the measure, which is the cost to the region as a whole considered by the TRC.

The TRC says nothing about the distributional impacts of the costs of energy efficiency. To address distributional effects, many jurisdictions that use the TRC as the primary criteria also look at other cost-effectiveness tests. In situations where budgets constrain the amount of energy efficiency investment, a threshold value may be used. A lower threshold may be applied to programs that serve low-income or hard-to-reach groups, representing the distinct societal value of reaching these customer groups that is not reflected in the benefit-cost calculation.

> The TRC is more restrictive than the PACT because it includes the full cost of the energy efficiency measure and not just the incentives paid by the utility. As a result, a program may have a positive PACT and PCT but still not pass the TRC, because the utility and customer pay a fraction of the total measure cost that is included in the TRC.

6.5 Societal Cost Test

The SCT includes all of the costs and benefits of the TRC, but it also includes environmental and other non-energy benefits that are not currently valued by the market. The SCT may also include non-energy costs, such as reduced customer comfort levels. Table 6-5 outlines the benefits and costs in the SCT.

Table 6-5. Benefits and Costs Included in the Societal Cost Test

Benefits and Costs to All in the Service Territory, State, or Nation as a Whole	
Benefits	**Costs**
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (e.g., gas and water if utility is electric) • Non-monetized benefits (and costs) such as cleaner air or health impacts	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or the utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

In some cases, emissions costs are included in the market price used to determine avoided costs or are otherwise explicitly included in the TRC calculation (as in the SCE program example[11]). Emissions permit costs may already be included in the market price of electricity in some jurisdictions. In other jurisdictions, emissions are included in the SCT.[12]

As with the TRC, the inclusion of tax incentives varies by jurisdiction. Those using a broad definition of the society exclude tax incentives as a transfer. Others will include tax incentives originating from outside the immediate region considered.

> The SCT includes costs and benefits beyond the immediate region and those that are not monetized in the TRC, such as environmental benefits or GHG reductions.

6.5.1 Additional Considerations

Increasingly, benefits historically included only in the SCT are being included in the TRC in some jurisdictions. Including a cost for carbon dioxide (CO_2) emissions is a prime example. Though the future cost associated with CO_2 emissions remains highly uncertain and difficult to quantify, many utilities believe it is increasingly unlikely that the cost will be zero. In California, an approximate forecast is developed through a survey of available studies and literature. The IRPs of many utilities now include a risk or portfolio analysis to calculate an "expected" carbon value or to determine if the additional cost of a flexible portfolio is sufficiently robust under a range of possible futures.

Water savings are also being explicitly included in the TRC instead of the SCT. This helps promote measures such as front-loading clothes washers, which provide water savings that are of value to the region but beyond the direct purview of electric and natural gas utilities. There is also increasing interest in the West, where water supply is particularly energy intensive, in targeting the energy savings possible through water conservation.[13]

Some commissions eschew the SCT because factors not included in the TRC are found to be beyond their jurisdiction. Where this is the case, legislation would be needed to create or clarify the opportunity for commissions to consider the SCT. On the other hand, some states require that the societal test be considered when commissions evaluate energy efficiency programs. Some states adopt the California methodology, while other states adopt modified versions, adding or deleting costs or benefits consistent with state priorities. For example, Illinois uses a modified TRC defined in statute, in which gas savings are not included in electricity program evaluation. The New York State Energy Research and Development Authority (NYSERDA) calculates the TRC for three scenarios, adding non-energy benefits in Scenario 2 and macroeconomic benefits in Scenario 3.

> Energy efficiency is among the most cost-effective ways to reduce carbon emissions. The SCT is a useful test for jurisdictions seeking to implement or comply with GHG reduction goals. It can also be used to evaluate water savings.

6.6 Notes

1 The PCT is only one of the determinants of customer participation, and bill savings are not the sole factor in a customer's decision to implement energy efficiency. Marketing and customer decision-making studies can be used to better understand the levels of customer participation more directly. See Golove and Eto, 1996; Schleich and Gruber, 2008.

2 At a minimum, overhead costs generally include the salary (and benefits) of those employees directly involved in promoting energy efficiency. Some jurisdictions opt to include an allocation of fixed costs (i.e., office space) while others do not. To the extent they are applicable, research and development, marketing, evaluation, measurement, and verification and other costs may be included in the overall total, or reported individually as they are for the SCE example shown here. In cases where energy efficiency program costs are subject to special treatment (e.g., public funding and shareholder incentive mechanisms), detailed definitions of what may be included as an overhead cost are often required.

3 The simplest example is a rebate paid to the customer for the purchase of an efficient appliance. However, as programs have grown in scope and complexity, so has the definition of an incentive. Two additional types of incentive are common: direct install costs and upstream payments. In many cases, the utility performs or pays for the labor and installation associated with an efficiency measure. Such payments, which are not for the equipment itself, but nevertheless reduce the cost to the customer, are considered direct install costs. Another approach, which is now common for CFL programs, calls for utilities to pay incentives directly to manufacturers and distributors. These upstream payments lower the retail cost of the product, though no rebate is paid directly to the customer.

4 Avoided cost benefits vary according to the time and location of the energy savings. Chapter 5 describes various alternative approaches for estimating the benefits of energy efficiency.

5 A specialized application of the PACT is in local IRPs. When a local area is at or near the system's capacity to serve its load, significant infrastructure investments are often required. If such investments can be deferred by reducing loads or load growth, there is additional value to the utility in installing energy efficiency and other distributed resources in that area. The additional savings that can be realized by the utility can justify increased customer incentives and marketing for a targeted efficiency program.

6 The RIM, PACT, and PCT assess the impacts of the program from different, but interconnected stakeholder perspectives. The RIM includes the overhead and incentive payments included as costs in the PACT, but also includes revenue losses. The RIM recognizes the incentives and bill savings reported as benefits in the PCT, but the RIM reports these terms as costs (revenues losses).

7 Even with a negative RIM result, efficiency may still be the most cost-effective means of meeting load growth. The full array of long-term investment options considered in utility resource planning cannot always be captured in the avoided costs used to evaluate energy efficiency.

8 The exception to the predominance of the negative RIM result are utilities that can serve most of their loads with existing, low-cost generation, but are facing high costs to build new generation. In such cases, the avoided costs for energy efficiency may well be higher that the utility's retail rates.

9 In practice, since utility rates are often frozen between rate-setting cycles and not continuously reset, the utility itself absorbs the losses (or gains) in its earnings until rates are adjusted. These adjustments can be made in several ways: the regular rate-setting cycle, a decoupling mechanism, or a revenue adjustment mechanism. In the long run, the reduced capital investments necessary as a result of energy efficiency will mitigate the rate increases. The National Action Plan for Energy Efficiency's Energy Efficiency Benefits Calculator can evaluate these impacts over time: <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/calculator.html>. This is discussed in more detail in Chapter 4.

10 As an example, in areas of competitive procurement, distribution-only utilities may not see energy efficiency as an immediate interest because it may not yield significant T&D savings (and generation costs are not part of their purview). In such a case, the utility may not implement energy efficiency even if it is cost-effective from a regional perspective. As a result, regulators may ask the utility to focus on the TRC rather than the PACT when evaluating efficiency programs.

11 California includes emissions permits and trading costs in the avoided cost calculations of the TRC.

12 Tax incentives paid by the state or federal governments and financing costs are excluded from the SCT, because they are considered a zero net transfer. A wide range of NEBs have been considered and evaluated throughout the United States. For the participant and community, these NEBs resulted in increased comfort, improved air quality, greater convenience, and improved health and aesthetic benefits. For the utility, fewer shut-off notices or bill complaints occurred.

13 The California Public Utilities Commission has approved pilot programs for investor-owned utilities to partner with water agencies and provide funding for water conservation incentives that provide energy savings (A.07-01-024).

Appendix A: National Action Plan for Energy Efficiency Leadership Group

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Appendix B: Glossary

Avoided costs: The forecasted economic benefits of energy savings. These are the costs that would have been spent if the energy efficiency had not been put in place.

Discount rate: A measure of the time value of money. The choice of discount rate can have a large impact on the cost-effectiveness results for energy efficiency. As each cost-effectiveness test compares the net present value of costs and benefits for a given stakeholder perspective, its computation requires a discount rate assumption.

Energy efficiency: The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. "Energy conservation" is a term that has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to perform the same or better function.

Evaluation, measurement, and verification: The process of determining and documenting the results, benefits, and lessons learned from an energy efficiency program. The term "evaluation" refers to any real time and/or retrospective assessment of the performance and implementation of a program. "Measurement and verification" is a subset of evaluation that includes activities undertaken in the calculation of energy and demand savings from individual sites or projects.

Free rider: A program participant who would have implemented the program measure or practice in the absence of the program.

Impact evaluation: Used to determine the actual savings achieved by different programs and specific measures.

Integrated resource planning: A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, integrated resource planning includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives.

Levelized cost: A constant value or payment that, if applied in each year of the analysis, would result in a net present value equivalent to the actual values or payments which change (usually increase) each year. Often used to represent, on a consistent basis, the cost of energy saved by various efficiency measures with different useful lives.

Marginal cost: The sum that has to be paid for the next increment of product or service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity.

Marginal emission rates: The emissions associated with the marginal generating unit in each hour of the day.

Market effects evaluation: Used to estimate a program's influence on encouraging future energy efficiency projects because of changes in the energy marketplace. All categories of programs can have market effects evaluations; however, these evaluations are primarily associated with market transformation programs that indirectly achieve impacts.

Market transformation: A reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects, that lasts after the intervention has been withdrawn, reduced, or changed.

Measures: Installation of equipment, installation of subsystems or systems, or modification of equipment, subsystems, systems, or operations on the customer side of the meter, in order to improve energy efficiency.

Net-to-gross ratio: A key requirement for program-level evaluation, measurement, and verification. This ratio accounts for only those energy efficiency gains that are attributed to, and the direct result of, the energy efficiency program in question. It gives evaluators an estimate of savings that would have occurred even without program incentives.

Net present value: The value of a stream of cash flows converted to a single sum in a specific year, usually the first year of the analysis. It can also be thought of as the equivalent worth of all cash flows relative to a base point called the present.

Nominal: For dollars, "nominal" means the figure representing the actual number of dollars exchanged in each year, without accounting for the effect of inflation on the value or purchasing power. For interest or discount rates, "nominal" means that the rate includes the rate of inflation (real rate plus inflation rate equals the nominal rate).

Participant cost test: A cost-effectiveness test that measures the economic impact to the participating customer of adopting an energy efficiency measure.

Planning study: A study of energy efficiency potential used by demand-side planners within utilities to incorporate efficiency into an integrated resource planning process. The objective of a planning study is to identify energy efficiency opportunities that are cost-effective alternatives to supply-side resources in generation, transmission, or distribution.

Portfolio: Either (a) a collection of similar programs addressing the same market, technology, or mechanisms or (b) the set of all programs conducted by one organization.

Potential study: A study conducted to assess market baselines and energy efficiency savings potentials for different technologies and customer markets. Potential is typically defined in terms of technical, economic, achievable, and program potential.

Program administrators: Typically procure various types of energy efficiency services from contractors (e.g., consultants, vendors, engineering firms, architects, academic institutions, community-based organizations), as part of managing, implementing, and evaluating their portfolio of energy efficiency programs. Program administrators in many states are the utilities; in some states they are state energy agencies or third parties.

Program design potential study: Can be undertaken by a utility or third party for the purpose of developing specific measures for the energy efficiency portfolio.

Ratepayer impact measure: A cost-effectiveness test that measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels of margin if a customer installed energy efficient measures.

Real: For dollars, "real" means that the dollars are expressed in a specific base year in order to provide a consistent means of comparison after accounting for inflation. For interest and discount rates, "real" means the inflation rate is not included (the nominal rate minus the inflation rate equals the real rate).

Societal cost test: A cost-effectiveness test that measures the net economic benefit to the utility service territory, state, or region, as measured by the total resource cost test, plus indirect benefits such as environmental benefits.

Time-of-use periods: Blocks of time defined by the relative cost of electricity during each block. Time-of-use periods are usually divided into three or four time blocks per 24-hour period (on-peak, mid-peak, off-peak, and sometimes super off-peak) and by seasons of the year (summer and winter).

Total resource cost test: A cost-effectiveness test that measures the net direct economic impact to the utility service territory, state, or region.

Utility/program administrator cost test: The program administrator cost test, also known as the utility cost test, is a cost-effectiveness test that measures the change in the amount the utility must collect from the customers every year to meet an earnings target—e.g., a change in revenue requirement. In a number of states, this test is referred to as the program administrator cost test. In those cases, the definition of the "utility" is expanded to program administrators (utility or third party).

Appendix B

Appendix C: Cost-Effectiveness Tables of Best Practice Programs

Southern California Edison Residential Incentive Program

SCE's Residential Energy Efficiency Incentive Program provides customer incentives for efficient lighting and appliances (not including HVAC). It is part of a coordinated statewide mass market efficiency program that coordinates marketing and outreach efforts. This program is used as the example in Section 3.1 to illustrate the calculation of each of the cost-effectiveness tests.

The values shown in Tables C-1, C-2 and C-3 are for the fourth quarter of 2006. Note that dollar benefits associated with emissions reductions are included in the forecasted avoided cost of energy, and are therefore not separately reported. The other category in this case includes direct implementation activity costs incurred by SCE that are over and above the cost of the efficiency measure. Direct installation costs paid by the utility that offset the cost of the measure are included under "program incentives."

Table C-1. SCE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	898,548	
Marketing and outreach	$	559,503	
Rebate processing	$	1,044,539	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other	$	992,029	
Total program administration	$	3,494,619	O
Program incentives			
Rebates and incentives	$	1,269,393	
Direct installation costs	$	564,027	
Upstream payments	$	13,624,460	
Total incentives	$	15,457,880	I
Total program costs	$	18,952,499	
Net measure equipment and installation	$	41,102,993	M

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators, <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Table C-2. SCE Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	2,795,290	$	187,904,906	
Peak demand (kW)	55,067		—	
Total electric	—	$	187,904,906	
Natural gas (MMBtu)	—		—	
Total resource savings		$	187,904,906	S
Participant bill savings	Electric	$	278,187,587	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	421,633		—	
SO_x	—		—	
PM_{10}	203,065		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	—	NEB

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators. <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Table C-3. SCE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results

Lifecycle costs and benefits

Test	Cost	Benefits	Ratio
PCT	$ 41,102,993	$ 293,645,467	7.14
PAC	$ 18,952,499	$ 187,904,906	9.91
RIM	$ 297,140,086	$ 187,904,906	0.63
TRC	$ 44,597,612	$ 187,904,906	4.21
SCT	$ 44,597,612	$ 187,904,906	4.21

Costs and benefits included in each test

PCT	= M	= B + I
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E
SCT	= O + M	= S + E + EXT + NEB

Estimated levelized costs and benefits

Test	Cost $/kWh	Benefits $/kWh
PCT	$0.026	$0.184
PAC	$0.012	$0.117
RIM	$0.186	$0.117
TRC	$0.028	$0.117
SCT	$0.028	$0.117

Assumptions for levelized calculations

Average measure life	14
WACC	8.50%
Discount factor for savings	57%

Source: SCE 4TH Quarter 2006 EE Report & Program Calculators. <http://www.sce.com/AboutSCE/Regulatory/eefilings/Quarterly.htm>.

Note: The discount factor uses an estimate of average measure life and the utility weighted average cost of capital to convert the net present value of costs and benefits into levelized annual figures. The levelized annual costs and benefits are then used to calculate costs and benefits on a $/kWh basis.

Avista Regular Income Programs

Avista is an electric and natural gas utility in the Northwest with headquarters in Spokane, Washington. The best practice program highlighted here represents the 2007 Regular Income Portfolio of electricity energy efficiency measures implemented by Avista. The numbers were obtained from the Triple-E Report produced by the Avista Demand-Side Management Team (Table 13E).

Avista reports gross results, which do not take free riders into account. Installation rates, persistence/failure and rebound ("snap-back" or "take-back") are taken into account in Avista's estimates of energy savings. Avista does consider NEBs when they are quantifiable and defensible, which are predominately benefits from the customer's perspective.

Avista contributed to projects saving over 53 million kWh and 1.5 million therms in 2007. The HVAC and lighting categories made up 81 percent of the electric savings while 97 percent of the natural gas savings were in the HVAC and Shell categories.

Avista incorporates quantifiable labor and operation and maintenance as non-energy benefits, which are included in the PCT, SCT, and TRC cost-effectiveness tests.

Table C-4. Avista Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,564,894	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	$	2,564,894	O
Program incentives			
Rebates and incentives	$	4,721,881	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	4,721,881	I
Total program costs	$	7,286,775	
Net measure equipment and installation	$	16,478,257	M

Source: Avista Triple-E Report, January 1, 2007—December 31, 2007.

Table C-5. Avista Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	—	$	30,813,091	
Peak demand (kW)	—		—	
Total electric	—	$	30,813,091	
Natural gas (MMBtu)	—	$	(355,426)	
Total resource savings		$	30,457,665	S
Participant bill savings	Electric	$	28,782,475	B
	Gas	$	(630,028)	
Monetized emission savings	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	12,595,276	NEB

Source: Avista Triple-E Report . January 1, 2007—December 31, 2007.

Table C-6. Avista Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	Cost	Benefits	Ratio
PCT	$ 11,756,376	$ 40,747,723	3.47
PAC	$ 7,286,775	$ 30,457,665	4.18
RIM	$ 36,069,250	$ 30,813,091	0.85
TRC	$ 19,043,151	$ 43,052,941	2.26
SCT	$ 19,043,151	$ 43,052,941	2.26

Costs and benefits included in each test

PCT	= M - I	= B + NEB
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E + NEB
SCT	= O + M	= S + E + EXT + NEB

Assumptions for levelized calculations

Average measure life	14
WACC	8.50%
Discount factor for savings	57%

Source: Avista Triple-E Report . January 1, 2007—December 31, 2007.

Puget Sound Energy Commercial/Industrial Retrofit Program

Puget Sound Energy's (PSE's) Commercial/Industrial Retrofit Program encourages customers to use electric and natural gas efficiently by installing cost- and energy-efficient equipment, adopting energy efficient designs, and using energy-efficient operations at their facilities. In addition, incentives are available for fuel switch measures that convert from electric to natural gas while serving the same end use. Applicable Commercial and Industrial Retrofit measure category headings include, but are not limited to: HVAC and refrigeration, controls, process efficiency improvements, lighting improvements, building thermal improvements, water heating improvements, and building commissioning.

Customers provide PSE with project costs and estimated savings. Customers assume full responsibility for selecting and contracting with third-party service providers. Projects must be approved for funding prior to installation/implementation. Maximum grants for hardware changes are based on PSE's cost-effectiveness standard. Grants for projects are made available as a percentage of the measure cost. Electric and gas measures may receive incentive grants up to 70 percent of the measure cost where the grant incentive does not exceed the cost-effectiveness standard minus program administration costs. Measures exceeding the cost-effectiveness standard will receive grants that are on a declining scale and will be less than 70 percent of the measure cost. Electric and gas measures that have a simple payback of less than a year are not eligible for a grant incentive.

Unlike the other programs presented in this document, PSE shows a positive RIM. A positive RIM is possible in the Pacific Northwest because of the allocation of low-cost hydro generation from the Bonniville Power Administration to municipal utilities. In some cases the marginal cost of avoided generation is determined by higher-cost thermal generation and is higher than the utility's average retail rate.

Table C-7. PSE Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	2,745,048	
Marketing and outreach		—	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification		—	
Shareholder incentive		—	
Other		—	
Total program administration	$	2,745,048	O
Program incentives			
Rebates and incentives	$	9,914,463	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	9,914,463	I
Total program costs	$	12,659,511	
Net measure equipment and installation	$	25,103,588*	M

Source: Data provided by Laura Feinstein at PSE.

* Total value

Table C-8. PSE Program Benefits

Net Benefit Inputs				Var.
Resource savings	Units		$	
Energy (MWh)	775,469	$	50,465,421	
Peak demand (kW)	—		—	
Total electric	—	$	50,465,421	
Natural gas (MMBtu)	661,480	$	2,575,451	
Total resource savings		$	53,040,873	S
Participant bill savings	Electric	$	33,297,727	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	—	NEB

Source: Data provided by Laura Feinstein at PSE.

Table C-9. PSE Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	Cost	Benefits	Ratio
PCT	$ 25,103,588	$ 43,212,190	1.72
PAC	$ 12,659,511	$ 53,040,873	4.19
RIM	$ 45,957,238	$ 53,040,873	1.15
TRC	$ 27,848,636	$ 53,040,873	1.90
SCT	$ 27,848,636	$ 53,040,873	1.90

Costs and benefits included in each test

PCT	= M	= B + I
PAC	= O + I	= S
RIM	= O + I + B	= S
TRC	= O + M	= S + E
SCT	= O + M	= S + E + EXT + NEB

Estimated levelized costs and benefits

Test	Cost $/kWh	Benefits $/kWh
PCT	$0.05	$0.09
PAC	$0.03	$0.11
RIM	$0.10	$0.11
TRC	$0.06	$0.11
SCT	$0.06	$0.11
Test	**Cost $/MMBtu**	**Benefits $/MMBtu**
PCT	$3.22	$5.54
PAC	$1.62	$6.80
RIM	$5.90	$6.80
TRC	$3.57	$6.80
SCT	$3.57	$6.80

Assumptions for levelized calculations

Average measure life	14
WACC	8.50%
Discount factor for savings	57%

Source: Data provided by Laura Feinstein at PSE.

National Grid MassSAVE Program

The Massachusetts MassSAVE program is a residential conservation program targeting electricity and natural gas savings. The data shown in the tables that follow are taken from the National Grid 2006 Energy Efficiency Annual Report, submitted to the Massachusettes Department of Energy Resources and Department of Public Utilities in August 2007.

In the residential sector, there are diminishing energy savings available from single-measure incentive programs, in part due to federal appliance and lighting standards, as well as rapid progress in increasing the market penetration of CFLs relative to incandescent lighting. As a result, more utilities are seeking to develop program models that tackle harder-to reach opportunities and offer more comprehensive savings. National Grid's Home Performance with ENERGY STAR is one such program model. This program offers comprehensive whole-house improvements (insulation, air sealing, duct sealing, and HVAC improvements) for homeowners. Customers receive in-home services, step-by-step guidance, incentives for energy measures, quality installations and inspections, and low-interest financing.

Since contractors that deliver home performance services are in short supply in most markets, an infrastructure building phase is typically needed. During the initial two- to three-year startup phase, program costs may be high relative to energy savings. However, as contracting services increase over time, energy savings tend to increase dramatically. Limiting cost-effectiveness tests to three-year program cycles or less may inadvertently limit the development of these long-term, comprehensive program models. National Grid was able to reduce administrative costs associated with contractor recruitment, training, and quality assurance by limiting contractor participation in program startup and by requiring participating contractors to directly install some measures.

Comprehensive, whole-building program models such as Home Performance with ENERGY STAR may face a number of additional challenges using commonly employed practice for calculating cost-effectiveness. For example, installing air sealing and insulation reduce heating and cooling loads, which reduces the savings associated with installing efficient HVAC equipment (interactive effects; see Section 3.2.1). However, reduced heating and cooling loads can also provide opportunities for downsizing heating and cooling systems, which are not captured by the cost-effectiveness tests. Furthermore, whole-house improvements provide a variety of non-energy benefits (Section 4.9) that can be difficult to quantify and are often not included as benefits in the cost-effectiveness tests.

More information can be found online at <http://www.masssave.com/customers/>.

Table C-10. National Grid Program Costs

Cost Inputs			Var.
Program overhead			
Program administration	$	760,324	
Marketing and outreach	$	296,628	
Rebate processing		—	
Research and development		—	
Evaluation, measurement, and verification	$	134,077	
Shareholder incentive		—	
Other		—	
Total program administration	$	1,191,029	O
Program incentives			
Rebates and incentives	$	3,507,691	
Direct installation costs		—	
Upstream payments		—	
Total incentives	$	3,507,691	I
Total program costs	$	4,698,720	
Net measure equipment and installation	$	2,452,985	M

Source: Data provided by Lynn Ross at National Grid.

Table C-11. National Grid Program Benefits

Net Benefit Inputs				Var.
Resource Savings	Units		$	
Energy (MWh)	46,385	$	2,550,000	
Peak demand (kW)	6,921		3,328,000	
Total electric	—	$	5,878,000	
Natural gas (MMBtu)	655,547		6,506,048	
Total resource savings		$	12,384,048	S
Participant bill savings	Electric	$	679,800	B
	Gas		—	
Monetized emission savings	Tons			
NO_x	7		—	
SO_x	19		—	
PM_{10}	—		—	
CO_2	1,576,374		—	
Total emissions		$	—	E
Non-monetized emissions (externalities)	Tons			
NO_x	—		—	
SO_x	—		—	
PM_{10}	—		—	
CO_2	—		—	
Total emissions			—	EXT
Non-energy benefits		$	155,601	NEB

Source: Data provided by Lynn Ross at National Grid.

Table C-12. National Grid Program Cost-Effectiveness Test Results

Summary of Cost-Effectiveness Results			
Lifecycle costs and benefits			
Test	Cost	Benefits	Ratio
PCT	$ 2,452,985	$ 4,187,491	1.71
PAC	$ 4,698,720	$ 12,384,048	2.64
RIM	$ 5,378,520	$ 12,384,048	2.30
TRC	$ 7,151,705	$ 12,384,048	1.73
SCT	$ 7,151,705	$ 12,539,649	1.75
Costs and benefits included in each test			
PCT	= M	= B + I	
PAC	= O + I	= S	
RIM	= O + I + B	= S	
TRC	= O + M	= S + E	
SCT	= O + M	= S + E + EXT + NEB	
Estimated levelized costs and benefits			
Test	Cost $/kWh	Benefits $/kWh	
PCT	$0.04	$0.06	
PAC	$0.07	$0.18	
RIM	$0.08	$0.18	
TRC	$0.10	$0.18	
SCT	$0.10	$0.18	
Test	Cost $/MMBtu	Benefits $/MMBtu	
PCT	$2.79	$4.76	
PAC	$5.34	$14.08	
RIM	$6.11	$14.08	
TRC	$8.13	$14.08	
SCT	$8.13	$14.26	
Assumptions for levelized calculations			
Average measure life		8	
WACC		8.50%	
Discount factor for savings		70%	

Source: Data provided by Lynn Ross at National Grid.

Appendix B

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Appendix B

Appendix B

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UNION ELECTRIC COMPANY
GAS SERVICE

Applying to MISSOURI SERVICE AREA

MISSOURI ENERGY EFFICIENT NATURAL GAS EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM

APPLICATION

The Missouri Energy Efficient Natural Gas Equipment and Building Shell Measure Rebate Program (Program) is designed to encourage more effective utilization of natural gas by encouraging energy efficiency improvements through the replacement of less efficient natural gas equipment with high efficient ENERGY STAR® Qualified natural gas equipment and other high efficiency equipment and building shell measures.

* Rebates are being offered on a limited basis for a portion of the cost of ENERGY STAR® Qualified or programmable thermostats, residential ENERGY STAR Qualified natural gas furnaces, residential high efficiency measures, commercial ENERGY STAR Qualified natural gas utilization equipment, as well as other high efficiency equipment and building shell measures purchased by Participants. Company's participation in such financial incentives is in accordance with the Stipulation and Agreement approved by the Missouri Public Service Commission (Commission) in Case No. GR-2010-0363.

DEFINITIONS

Administrator - Company will administer the Program.

AFUE - Annual Fuel Utilization Efficiency: Energy efficiency rating measure determined, under specific testing conditions, by dividing the energy output by the energy input. It is a measure of the heat actually delivered by a furnace to the structure compared to the heat potential in amount of fuel supplied to the furnace. For example, a furnace that has a 92% AFUE rating converts 92% of the fuel supplied as heat to the structure - the other 8% is lost as exhaust. This information is available on every furnace sold in the United States.

ENERGY STAR® - A voluntary labeling program designed to identify and promote energy efficient products to reduce energy expenses and greenhouse gas emissions. ENERGY STAR® is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy.

Participant - A customer who is being served under either the Company's Residential or General Service natural gas rate class, is located in Missouri, and elects to purchase energy efficient gas saving equipment as described in the Measures. For purposes of receiving rebates under this Program, a Participant is defined as a person, firm, organization, association, corporation, or other entity that implements Measure(s), submits Rebate Form and documentation.

Retailer - Any retailer which has agreed to sell ENERGY STAR® Qualifying or other high efficient natural gas equipment, or provider of energy efficiency services, associated with the Measures.

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GAS SERVICE

Applying to MISSOURI SERVICE AREA

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MISSOURI ENERGY EFFICIENT NATURAL GAS
EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

DEFINITIONS (cont'd)

Qualified Auditor - A nationally recognized contractor trained in natural gas equipment utilization systems and commercial and/or residential structures as an integrated whole building system. Residential training, certification, and accreditation are provided by the Building Performance Institute (BPI) and Residential Energy Services Network's (RESNET®). Commercial training and certification are provided by nationally-respected energy auditor certification organizations. Approved Energy Auditors are found in the Company's Value Added Partner Network.

* EEAG - Energy Efficiency Advisory Group: Includes representatives from the Company, the Commission Staff, Office of the Public Counsel, and the Department of Natural Resources - Division of Energy. The EEAG will function as an advisory group for these programs.

AVAILABILITY

The Program is voluntary and a Participant may only receive one rebate per listed measure per calendar year. Rebates must be redeemed through the Administrator. Participating Retailers can be determined by visiting Company's Website (www.ameren.com) or by calling 314-342-1111 or 1-800-552-7583.

Residential rebates apply only to Residential customers purchasing ENERGY STAR® Qualified or programmable thermostats, ENERGY STAR Qualified residential natural gas utilization equipment, and other high energy efficient natural gas equipment and building shell measures as listed in Residential Measures.

General Service rebates apply only to General Service customers purchasing ENERGY STAR® Qualified or programmable thermostats, ENERGY STAR Qualified natural gas utilization equipment, high efficiency rated natural gas utilization equipment and other high efficiency equipment and building shell measures as listed in General Service Measures.

REBATES

Each Participant will receive a rebate check from the Administrator within eight (8) to ten (10) weeks after the completed Rebate Form is submitted with proper documentation. Rebate Forms, applications and protocols are available on the Company's Website (www.ameren.com) or by calling 314-342-1111 or 1-800-552-7583.

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EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

The terms of the rebate(s) are as follows:

Residential Measures

1) Equipment: Thermostat - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified or Programmable.
Rebate: Twenty five dollars ($25) or 50% of the equipment cost, whichever is lower.

*2) Equipment: Natural Gas Furnace - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified high efficiency AFUE rated 92% to 95.9%.
Rebate: One hundred and fifty dollars ($150) or 50% of the equipment cost, whichever is lower.

*3) Equipment: Natural Gas Furnace - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified high efficiency AFUE rated 96% or higher.
Rebate: Two hundred dollars ($200) or 50% of the equipment cost, whichever is lower.

*4) Equipment: Natural Gas Boiler - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified high efficiency AFUE rated 90% or higher.
Rebate: One hundred and fifty dollars ($150) or 50% of the equipment cost, whichever is lower.

*5) Equipment: Natural Gas Tank Storage Water Heater (Tier I) - purchase and installation of one (1) unit.
Rated: High efficiency with an EF rating greater than or equal to 0.62 and less than 0.67.
Rebate: Fifty dollars ($50) or 50% of the equipment cost, whichever is lower.

*6) Equipment: Natural Gas Tank Storage Water Heater (Tier II) - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified high efficiency with EF rating of at least 0.67 and higher.
Rebate: One-hundred and twenty-five dollars ($125) or 50% of the equipment cost, whichever is lower.

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EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

Residential Measures (cont'd)

*7) Equipment: Natural Gas Tank Storage or Tankless Water Heater - purchase and installation of one (1) unit.
Rated: ENERGY STAR® Qualified high efficiency with an EF rating of 0.82 or higher.
Rebate: Two hundred dollars ($200) or 50% of the equipment cost, whichever is lower.

*8) Equipment: Building Shell Measures - Residential Home Energy Audit Improvement - purchase and installation of cost effective natural gas energy saving equipment and building shell measures as recommended from customer paid energy audit from a Qualified Auditor which are not included in other residential natural gas measures listed in this Program.
Rated: Measures considered efficiency improvements include:

1. Ceiling or wall insulation
2. Energy Star windows and doors
3. Window weather stripping
4. Door weather stripping
5. Water heater wrap
6. Hot water pipe wrap
7. Switch and outlet insulation
8. Caulking
9. Faucet aerators
10. Low flow shower heads

Rebate: Two hundred and fifty dollars ($250) or 50% of the equipment and building shell measures cost up to maximum rebate of two hundred and fifty dollars ($250) whichever is lower.

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EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

General Service Measures

1) Equipment: Thermostat - purchase and installation of up to two (2)units.
Rated: ENERGY STAR® Qualified or Programmable.
Rebate: Forty dollars ($40) per thermostat, eighty dollars ($80) total or 50% of the equipment cost, whichever is lower.

*2) Equipment: Natural Gas Furnace - purchase and installation of one (1) unit less than 150,000 BTU.
Rated: ENERGY STAR® Qualified high efficiency AFUE rated 92% to 95.9%.
Rebate: One hundred and fifty dollars ($150) or 50% of the equipment cost, whichever is lower.

*3) Equipment: Natural Gas Furnace - purchase and installation of one (1) unit of less than 150,000 BTU.
Rated: ENERGY STAR® Qualified high efficiency AFUE rated 96% or higher.
Rebate: Two hundred dollars ($200) or 50% of the equipment cost, whichever is lower.

4) Equipment: Natural Gas Furnace - purchase and installation of one (1) unit of 150,000 BTU or greater.
Rated: High Efficiency AFUE rated 90% or higher.
Rebate: Four hundred seventy five dollars ($475) or 50% of the equipment cost, whichever is lower.

5) Equipment: Steam Trap Replacement - purchase and replacement of up to twenty five (25) failing units.
Rated: Steam Trap replacement considered efficiency improvement.
Rebate: One hundred dollars ($100) per steam trap; two thousand five hundred ($2,500) total or 50% of the equipment cost, whichever is lower.

6) Equipment: Natural Gas Continuous Modulating Burner New Installation or Burner Replacement - purchase and installation of modulating burner only.
Rated: Burner replacement considered efficiency improvement.
Rebate: Seven thousand five hundred dollars ($7,500) or 25% of the equipment cost, whichever is lower.

7) Equipment: Natural Gas Fired Boiler Tune-up - tune-up of a Gas Fired Burner System.
Rated: Tune-up considered efficiency improvement.
Rebate: Five hundred dollars ($500) per boiler or 50% of the cost, whichever is lower.

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General Service Measures (cont'd)

8) Equipment: Primary Air Damper - Purchase and replacement of one (1) damper unit.
Rated: Damper replacement considered efficiency improvement.
Rebate: Five hundred dollars ($500) or 50% of the equipment cost, whichever is lower.

9) Equipment: Natural Gas Food Service Steamer - purchase and installation of one (1) food service steamer.
Rated: ENERGY STAR® Qualified.
Rebate: Four hundred seventy five dollars ($475) or 50% of the equipment cost, whichever is lower.

10) Equipment: Natural Gas Food Service Fryer - purchase and installation of one (1) food service fryer.
Rated: ENERGY STAR® Qualified.
Rebate: Three hundred fifty dollars ($350) or 50% of the equipment cost, whichever is lower.

11) Equipment: Natural Gas Food Service Griddle - purchase and installation of one (1) food service griddle.
Rated: ENERGY STAR® Qualified.
Rebate: Four hundred dollars ($400) or 50% of the equipment cost, whichever is lower.

12) Equipment: Natural Gas Food Service Oven - purchase and installation of one (1) food service oven.
Rated: ENERGY STAR® Qualified.
Rebate: Two hundred dollars ($200) or 50% of the equipment cost, whichever is lower.

*13) Equipment: Natural Gas Tank Storage Water Heater (Tier I) - purchase and installation of up to two (2) units.
Rated: High efficiency with an EF rating greater than or equal to 0.62 and less than 0.67.
Rebate: Fifty dollars ($50) per unit, one hundred dollars ($100) total or 50% of the equipment cost, whichever is lower.

*14) Equipment: Natural Gas Tank Storage Water Heater (Tier II) - purchase and installation of up to two (2) units.
Rated: ENERGY STAR® Qualified high efficiency with EF rating of at least 0.67 and higher.
Rebate: One-hundred and twenty-five dollars ($125) per unit, two hundred and fifty dollars ($250) total or 50% of the equipment cost, whichever is lower.

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MISSOURI ENERGY EFFICIENT NATURAL GAS
EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

General Service Measures (cont'd)

*15) Equipment: Natural Gas Tank Storage or Tankless Water Heater - purchase and installation of up to two (2) units.
Rated: ENERGY STAR® Qualified high efficiency with an EF rating of 0.82 or higher.
Rebate: Two hundred dollars ($200) per unit, four hundred dollars ($400) total or 50% of the equipment cost, whichever is lower.

**16) Equipment: Natural Gas Boiler Replacement
Rated: Replace an existing boiler with a high efficient model.
Rebate: <300,000 Btuh and AFUE ≥ 85%: $1.50/MBtuh input or $500, whichever is lower. >300,000 Btuh and TE ≥ 90%: $3/MBtuh input or $2,000, whichever is lower.

**17) Equipment: Building Shell Measures - Commercial Energy Audit Improvement - purchase and installation of cost effective natural gas energy saving equipment and building shell measures as recommended from a customer paid energy audit by a Qualified Auditor, which are not included in other commercial measures listed in this Program.
Rated: Measures considered efficiency improvements include:
1. Ceiling or wall insulation
2. Energy Star windows and doors
3. Window weather stripping
4. Door weather stripping
5. Water heater wrap
6. Hot water pipe wrap
7. Switch and outlet insulation
8. Caulking
9. Faucet aerators
10. Low flow shower heads

Rebate: One thousand dollars ($1,000), or 50% of the equipment and building shell measures cost, whichever is lower

**18) Equipment: Building Shell Measures - General Service Non-Energy Audit Improvement - purchase and installation of cost effective natural gas energy saving equipment and building shell measures that the customer believes are needed to improve the energy efficiency of their business and are not included in other commerical natural gas measures listed in this Program.

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EQUIPMENT AND BUILDING SHELL MEASURE REBATE PROGRAM (cont'd)

General Service Measures (cont'd)

Rated: Measures considered efficiency improvements include:
1. Ceiling or wall insulation
2. Energy Star windows and doors
3. Window weather stripping
4. Door weather stripping
5. Water heater wrap
6. Hot water pipe wrap
7. Switch and outlet insulation
8. Caulking
9. Faucet aerators
10. Low flow shower heads

Rebate: Twenty five percent (25%) of the cost for equipment and building shell measures. A rebate will only be issued when the calculated rebate results in a minimum rebate of at least one hundred ($100) and the total rebate issued cannot exceed a maximum rebate of one thousand dollars ($1,000).

***PROGRAM FUNDS**

Funding for these measures is set forth in the Stipulation and Agreement in Case No. GR-2010-0363.

***PROGRAM TERM**

The Program will conclude December 31, 2012.

This tariff will provide for uninterrupted availability of these energy efficiency programs through December 31, 2012. The Company may file with the Commission proposed revised tariff sheets concerning the Energy Efficiency program if Company believes circumstances warrant changes.

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CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

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Chapter 1

Basic Methodology

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives-participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the "Non-Participant Test" to the "Ratepayer Impact Test"; (2) renaming the All-Ratepayer Test" to the "Total Resource Cost Test."; (3) treating the "Societal Test" as a variant of the "Total Resource Cost Test;" and, (4) an expanded explanation of "demand-side" activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for "cost effective conservation and energy efficiency" for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency — the Consumer Power and Conservation Financing Authority — was created. This agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand-Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I
Cost-Effectiveness Tests

Participant	
Primary	Secondary
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in **Table 1** is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used.

Externality Values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

Participant Test

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the societal test should also be performed.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

How the Results can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

[2] It should be noted that if a demand-side program is beneficial to its participants ($NPVp \geq 0$ and $BCRp \geq 1.0$) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

NPV_P	=	Bp - Cp
NPVavp	=	(Bp - Cp) / P
BCRp	=	Bp / Cp
DPp	=	Min j such that Bj > Cj

Where:

NPVp	=	Net present value to all participants
NPVavp	=	Net present value to the average participant
BCRp	=	Benefit-cost ratio to participants
DPp	=	Discounted payback in years
Bp	=	NPV of benefit to participants
Cp	=	NPV of costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
J	=	First year in which cumulative benefits are cumulative costs.
d	=	Interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Where:

BRt	=	Bill reductions in year t
Bit	=	Bill increases in year t

TCt	=	Tax credits in year t
INCt	=	Incentives paid to the participant by the sponsoring utility in year t[3]
PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax[4] • Ongoing operation and maintenance costs include fuel cost • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PACat	=	Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)
Abat	=	Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I}(\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I}(\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I}(\Delta EG_{it} \times AC:E_{it} \times (K_{it}-1)) + \sum_{i=1}^{I}(\Delta DG_{it} \times AC:D_{it} \times (K_{it}-1)) + OBI_t$$

Where:

ΔEG_{it}	=	Reduction in gross energy use in costing period i in year t
ΔDG_{it}	=	Reduction in gross billing demand in costing period i in year t
$AC:E_{it}$	=	Rate charged for energy in costing period i in year t

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

$AC{:}D_{it}$	=	Rate charged for demand in costing period i in year t
K_{it}	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (e.g.,, customer charges, standby rates).
OBI_t	=	Other bill increases (i.e. customer charges, standby rates).
I	=	Number of periods of participant's participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

Chapter 3

The Ratepayer Impact Measure Test[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

How the Results can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue

[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g.,, funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements.

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = I
ARIRIMt	=	FRIRIM	for t = I
	=	(CRIMt - BRIMt)/Et	for t=2, ..., N
NPVRIM	=	BRIM-CRIM	

BCRRIM` = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARIRIM = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')

NPVRIM = Net present value levels

BCRRIM = Benefit-cost ratio for rate levels

BRIM = Benefits to rate levels or customer bills
CRIM = Costs to rate levels or customer bills
E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRIRIM test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where:

UACt = Utility avoided supply costs in year t
UICt = Utility increased supply costs in year t
RGt = Revenue gain from increased sales in year t
RLt = Revenue loss from reduced sales in year t
PRCt = Program Administrator program costs in year t
Et = System sales in kWh, kW or therms in year t or first year customers
UACat = Utility avoided supply costs for the alternate fuel in year t
Rlat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC : E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC : D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I} (\Delta EN_{it} \times MC : E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC : D \times (K_{it} - 1))$$

Where:

[Only terms not previously defined are included here.]

ΔENit	=	Reduction in net energy use in costing period i in year t
ΔDNit	=	Reduction in net demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
MC:Dit	=	Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RGt	=	BIt	* (net-to-gross ratio)
RLt	=	BRt	* (net-to-gross ratio)
Rlat	=	Abat	* (net-to-gross ratio)

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

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[6] This test was previously called the All Ratepayers Test

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test expressed in terms of net present value, a benefit-cost ratio, or levelized costs is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g.,, kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPVTRC) is the discounted value of the net benefits to this test over a specified period of time. NPVTRC is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCRTRC) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit-cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain externality costs of power generation not captured by the market system. An illustrative and

7 Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make

by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
   a. Avoided costs of supply disruptions
   b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
   c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
   d. Benefits to customers and the public of avoiding blackouts.

5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.

6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test'. This test and the sepcific benefits associated with this test are outside the scope of this manual.

7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management.

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

NPVTRC = BTRC - CTRC
BCRTRC = BTRC /CTRC
LCTRC = LCRC / IMP

Where:

NPVTRC = Net present value of total costs of the resource
BCRTRC = Benefit-cost ratio of total costs of the resource
LCTRC = Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)
BTRC = Benefits of the program
CTRC = Costs of the program
LCRC = Total resource costs used for levelizing
IMP = Total discounted load impacts of the program
PCN = Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[(\sum_{t=1}^{n} \Delta EN_{it})\, or\, (\Delta DN_{it}\ where\ I = peak\ period) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

Program Administrator Cost Test

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator's overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPVpa) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCRpa) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$$\begin{aligned} NPVpa &= Bpa - Cpa \\ BCRpa &= Bpa/Cpa \\ LCpa &= LCpa/IMP \end{aligned}$$

Where:

NPVpa	Net present value of Program Administrator costs
BCRpa	Benefit-cost ratio of Program Administrator costs

LCpa	Levelized cost per unit of Program Administrator cost of the resource
Bpa	Benefits of the program
Cpa	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the Bpa equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A

Inputs to Equations and Documentation

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.

2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.

3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.

4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.

6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.

7. The development and treatment of load impact estimates should distinguish between gross (i.e., impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.

8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g.,, termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP	=	BP - CP
NPVavp	=	(BP - CP) / P
BCRP	=	BP/CP
DPP	=	min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = 1
ARIRIMt	=	FRIRIM	for t = 1
	=	(CRIMt- BRIMt)/Et	for t=2,... ,N
NPVRIM	=	BRIM — CRIM	
BCRRIM	=	BRIM /CRIM	

Total Resource Cost Test

NPVTRC	=	BTRC - CTRC
BCRTRC	=	BTRC / CTRC
LCTRC	=	LCRC / IMP

Program Administrator Cost Test

NPVpa	=	Bpa - Cpa
BCRpa	=	Bpa / Cpa
LCpa	=	LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \sum_{t=1}^{n} \frac{\left[(\sum_{i=1}^{n} \Delta EN_{it}) \, or \, (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are $>$ cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Appendix C.

Derivation of Rim Lifecycle Revenue Impact Formula

Most of the formulas in the manual are either self-explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRIRIM) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPVRIM The amount which present valued revenues are below present valued revenue requirements equals NPVRIM

The LRIRIM is the change in rates that creates a change in the revenue stream that, when present valued, equals the NPVRIM* If the utility raises (or lowers) its rates in the base year by the amount of the LRIRIM' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRIRIM is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the NPVRIM or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times E_t}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Big/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$