ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 2017-00384

Responses to Commission Staff's
First Request for Information
dated
June 22, 2018

Volume 4 of 4
Item Nos. 41 through 57

FILED: July 20, 2018

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 41)   *Refer to Appendix A, Section 4.4, Forecast Model Specification,*

2   *page 50. Explain why only Jackson Purchase Energy Corporation includes*

3   *the average use from the prior year as an independent variable and the other*

4   *Members do not.*

5   .

6   **Response)** The sentence *"The model for JPEC also includes average use from the*

7   *prior year as an independent variable"* in Appendix A, Section 4.4, Forecast Model

8   Specification, page 50, should have been deleted from the Big Rivers 2017 Load

9   Forecast report prior to its final publication. The final small commercial use per

10   customer model specification for Jackson Purchases Energy Corporation did not

11   include average use from the prior year as an independent variable.

12

13

14   **Witness)**   John W. Hutts

15

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 42)   *Refer to Appendix A, Section 1.3.5, Big Rivers Consumer Classes,*

2   *page 4. By year, provide the estimated portion of sales, previously associated*

3   *with the smelters, that is projected to be absorbed by growth by Member load*

4   *and non-Member sales.*

5

6   **Response)** Please see the following table.

7

Big Rivers Electric Corporation Estimated Portion of Smelter Sales to be Absorbed		
Year	Native Member Demand Growth (% of Lost Smelter Load)	Total Non-Member Demand Sales (% of Lost Smelter Load)
2017	2 %	57 %
2018	1 %	59 %
2019	2 %	59 %
2020	0 %	59 %
2021	0 %	59 %
2022	0 %	59 %
2023	0 %	59 %
2024	0 %	59 %
2025	0 %	59 %
2026	0 %	59 %
2027	0 %	59 %
2028	0 %	59 %
2029	0 %	58 %
2030	0 %	56 %

8

9

10

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1

Big Rivers Electric Corporation Estimated Portion of Smelter Sales to be Absorbed (*continued*)		
Year	Native Member Demand Growth (% of Lost Smelter Load)	Total Non-Member Demand Sales (% of Lost Smelter Load)
2031	0 %	56 %
2032	0 %	55 %
2033	0 %	55 %
2034	0 %	54 %
2035	0 %	54 %
2036	0 %	53 %

2

3

4   **Witness)**   Marlene S. Parsley

5

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOUCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 43)   *Refer to Appendix A, Section 1.5, Load Forecast Summary. Refer*

2   *to page 6, Table 1.2. Explain why the load factor decreased from 61.8 percent*

3   *to 36.1 percent between 2016 and 2017.*

4

5   **Response)** Peak demand values presented in Appendix A, Section 1.5, Load

6   Forecast Summary, page 6, Table 1.2, include expected load associated with

7   optimized economic sales beginning in 2017. Optimized economic sales are the result

8   of evaluation of costs to deliver Big Rivers' generation versus buying from the market,

9   therefore Energy requirements in Table 1.2 do not include energy associated with

10   projected optimized economic sales.

11

12

13   **Witness)**   John W. Hutts

14

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 44)   *Refer to Appendix A, Section 3, Load Forecast Results.*

2   a.   *Refer to Table 3.2 on page 18.*

3   *(1) Explain why transmission losses increased throughout the*

4   *forecast period.*

5   *(2) Explain how transmission losses are forecasted.*

6   b.   *Refer to Table 3.13 on page 30. Explain why the load factor declines*

7   *between 2017 and 2018.*

8   c.   Refer to the residential section on page 35.

9   *(1) Explain why a 3.5 percent increase in average growth in*

10   *household income was chosen for the optimistic case, and a 0.5*

11   *percent increase in average growth was chosen for the*

12   *pessimistic scenario.*

13   *(2) Explain why the optimistic and pessimistic scenarios of price*

14   *elasticity of -0.11 and -0 .31, respectively, were chosen.*

15   *(3) Provide support as to why an average growth rate of 50 percent*

16   *above the base case customer forecast was chosen for the*

17   *optimistic forecast and why an average growth rate 75 percent*

18   *below the base case customer forecast was selected for the*

19   *pessimistic forecast.*

20   d.   *Refer to the Small Commercial section on page 35. Explain why an*

21   *optimistic customer forecast reflecting an average growth rate of 50*

22   *percent above the base case forecast and a pessimistic customer*

23   *forecast 75 percent below the base case is appropriate.*

Case No. 2017-00384
Response to PSC 1-44
Witnesses: Christopher S. Bradley (*a.(1) only*) and
John W. Hutts (*a.(2), b., c. and d. only*)
Page 1 of 4

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1

2. **Response)**

3   a.

4   (1)   Transmission losses can be impacted by generation dispatch, load

5   levels, transmission configuration, off system sales and purchases,

6   parallel flows, and other factors. It is not possible to definitively

7   determine the factors that impacted the loss values included in Table

8   3.2.

9   (2)   Transmission losses were forecasted to remain constant at the

10   anticipated 2017 level.

11   b.   In Table 3.13, total system load factor drops in 2018 because energy

12   requirements do not include optimized economic sales, while Non

13   Coincident Peak includes executed sales of capacity and projected sales.

14   c.

15   (1)   The percentage increases for the optimistic and pessimistic cases were

16   chosen following an analysis of historical annual growth rates for each

17   of Big Rivers' Members. The 0.5 and 3.5 percent increases were

18   concluded to be reasonable representations of percent changes in

19   average household income under long term pessimistic and optimistic

20   scenarios for each Member.

21   (2)   The elasticity values presented in Appendix A, Section 3, Load

22   Forecast Results, page 35 represent the average for Big Rivers. The

23   high and low case forecast scenarios were developed individually for

Case No. 2017-00384
Response to PSC 1-44
Witnesses: Christopher S. Bradley (*a.(1) only*) and
John W. Hutts (*a.(2), b., c. and d. only*)
Page 2 of 4

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1		each Big Rivers Member. The optimistic and pessimistic scenarios of
2		price elasticity were set at +/- 0.10 of each Member's respective base
3		case value.
4	(3)	Changes in annual Residential customer growth for Big Rivers'
5		Members does not appear to be normally distributed (i.e., the absolute
6		difference between average annual growth in low growth years and the
7		overall long term average is greater than the absolute difference
8		between average annual growth in the high years and the long term
9		average. The assumption of an average growth rate of 50 percent above
10		the base case customer forecast for the optimistic forecast and an
11		average growth rate 75 percent below the base case forecast for the
12		pessimistic forecast reflects the assumption that variations in annual
13		Residential customer growth will be similar to those of past years.
14	d.	Changes in annual Small Commercial customer growth for Big Rivers'
15		Members does not appear to be normally distributed (i.e., the absolute
16		difference between average annual growth in low growth years and the
17		overall long term average is greater than the absolute difference between
18		average annual growth in the high years and the long term average. The
19		assumption of an average growth rate of 50 percent above the base case
20		customer forecast for the optimistic forecast and an average growth rate 75
21		percent below the base case forecast for the pessimistic forecast reflects the
22		assumption that variations in annual Small Commercial customer growth
23		will be similar to those of past years

Case No. 2017-00384
Response to PSC 1-44
Witnesses: Christopher S. Bradley (*a.(1) only*) and
John W. Hutts (*a.(2), b., c. and d. only*)
Page 3 of 4

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1

2

3   **Witnesses)** Christopher S. Bradley *(a.(1) only)* and

4   John W. Hutts *(a.(2), b., c. and d. only)*

5

Case No. 2017-00384
Response to PSC 1-44
Witnesses: Christopher S. Bradley *(a.(1) only)* and
John W. Hutts *(a.(2), b., c. and d. only)*
Page 4 of 4

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 45)   *Refer to Appendix A, Annual Forecast Tables, and Graphs, page*

2   *A-6. The historical annual sales growth rates for native system sales to*

3   *members have been negative to flat; however, the first five years of the*

4   *forecast period are projected to increase by 1.5 percent over the 2016-2021*

5   *time period. Explain why the sales forecast is more optimistic during this*

6   *time period.*

7

8   **Response)** The average annual compound growth rate of 1.5 percent per year over

9   the 2016-2021 period for native sales is predominately due to planned expansions of

10   operations by two direct serve customers, beginning during mid-2017 and increasing

11   annually through 2020. Net of these expansions, the average annual compound

12   growth rate would fall to 0.3 percent per year over the same time period.

13

14

15   **Witness)**   John W. Hutts

16

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 46)**   *Refer to Appendix A, Appendix C, Forecast Model Specifications.*

2   a.   *Explain how Big Rivers transitioned from the short-term model to*

3   *the long-term model.*

4   b.   *Describe any instances when the long-term model incorporates a*

5   *structural shift in the underlying economy within the first 24*

6   *months of the forecast horizon and how Big Rivers handled this*

7   *structural shift in the forecast.*

8   c.   *Refer to the model outputs for each member system.*

9   *1.   Explain what the reclass variable represents.*

10   *2.   For each forecasting model, if the input variables vary between*

11   *each member system, explain why each member system has*

12   *differing input variables. For example, explain why the Long*

13   *Term Residential customer model for Meade County has a*

14   *lagged customer variable and a monthly reclass variable, while*

15   *Jackson Purchase and Kenergy does not.*

16

17   **Response)**

18   a.   Short-term and long-term customer models were developed for the

19   Residential and Small Commercial classifications for each of Big Rivers'

20   three Members. The transition from the short-term to the long-term models

21   were made as follows:

22

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Meade County** – For the Residential class, the customer forecast in all

2   years of the forecast period was based on the long-term model. For the

3   Small Commercial class, the customer forecast in 2017 and 2018 was

4   computed as the sum of (1) the number of customers in prior year, and

5   (2) the projected annual growth in customers in 2017 and 2018 from the

6   short-term model. Projections for 2019 and beyond were computed as

7   the sum of (1) the number of customers in prior year, and (2) the

8   projected annual growth in customers for the respective forecast year

9   from the long-term model.

10   **Jackson Purchase** – For the Residential class, the customer forecast

11   in 2017 was computed as the sum of (1) the number of customers in prior

12   year, and (2) the projected annual growth in customers in 2017 from the

13   short-term model. The projections for 2018 and beyond was computed

14   as the sum of (1) the number of customers in prior year, and (2) the

15   projected annual growth in customers for the respective forecast year

16   from the long-term model. For the Small Commercial class, the

17   customer forecast in 2017 was computed as the sum of (1) the number of

18   customers in prior year, and (2) the projected annual growth in

19   customers in 2017 from the short-term model. The projections for 2018

20   and beyond was computed as the sum of (1) the number of customers in

21   prior year, and (2) the projected annual growth in customers for the

22   respective forecast year from the long-term model.

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1	**Kenergy Corp.** – For the Residential class, the customer forecast in
2	2017 and 2018 was computed as the sum of (1) the number of customers
3	in prior year, and (2) the projected annual growth in customers in 2017
4	and 2018 from the short-term model. Projections for 2019 and beyond
5	were computed as the sum of (1) the number of customers in prior year,
6	and (2) the projected annual growth in customers for the respective
7	forecast year from the long-term model. For the Small Commercial
8	class, the customer forecast in 2017 was computed as the average of the
9	customer projections from the short-term and long-term models.
10	Projections for 2018 and beyond were based on the long-term model.
11	
12	b. The long-term models do not incorporate a structure shift in the underlying
13	economy within the first 24 months of the forecast horizon.
14	c. Regarding the model outputs for each Member system
15	1. The reclass variables are binary date series that account for the
16	reclassification of customer accounts in a particular year. The variable
17	takes a value of 0 for all time periods prior to the reclassification and
18	a value of 1 for all time periods after the reclassification of accounts.
19	2. The forecast model development phase began by specifying and testing
20	the same consumer, energy use, and peak demand model specifications
21	across all three Members. In all instances, the same theoretical
22	assumptions are consistent across Members. The number of
23	Residential customers is driven by number of service area households.

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1 The number of Small Commercial customers is driven by changes in

2 employment. Residential and Small Commercial use per customer is

3 driven by economic activity, electricity prices, end-use market shares

4 and efficiencies, and weather conditions. Regression models are tools

5 used to quantify these driving influences and provide forecasters

6 information for developing a final forecast. While the same driving

7 influences on energy and peak demand requirements are captured in

8 the models for each Member, the specifications for some models may

9 be revised to be produce a model that captures unique characteristics

10 in the data. The following discussion addresses the differences in

11 models across the three Members:

12

13 **Residential Customer Model - Short-Term** – There are no

14 differences between the Jackson Purchase and Kenergy models. The

15 model for Meade County includes a binary variable to account for a

16 customer reclassification of accounts. Additionally, an autoregressive

17 parameter was not included in the Meade County (note that the Meade

18 County model was not used in development of the forecast).

19 **Residential Customer Model - Long-Term** – There are no

20 differences between the Jackson Purchase and Kenergy models. The

21 model for Meade County also includes a binary variable to account for

22 a customer reclassification of accounts and a lag of the dependent

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   variable to produce a more reasonable customer projection for 2017

2   than a model without the lagged parameter.

3   **Small Commercial Customer Model – Short-Term** – The models

4   for all three Members are the same.

5   **Small Commercial Customer Model – Short-Term** – The models

6   for all three Members include an employment parameter. The

7   Kenergy and Meade County models include an autoregressive

8   parameter to address first-order autocorrelation. An autoregressive

9   parameter was not included in the Jackson Purchase model since it

10   did not improve the customer forecast. The Meade model includes a

11   binary variable to account for a customer reclassification of accounts.

12   **Residential Average Use** – All three Member models include the

13   driving base, heating, and cooling parameters. Each of the three

14   Member models include a unique series of monthly binary variables to

15   account for differences between billing cycle energy (dependent

16   variable) and calendar month weather in the heating and cooling

17   independent variables. The Kenergy model also includes an

18   autoregressive parameter to address first-order autocorrelation.

19   **Small Commercial Use** – All three Member models include weather

20   and appliance efficiency parameters (degree days weighted by

21   efficiency). The Meade County and Kenergy models include an auto-

22   regressive parameter to address first-order autocorrelation. The

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Kenergy model includes a binary variable to account for a

2   reclassification of accounts that occurred in 2013.

3   **Rural System Peak Demand** – All three models include energy and

4   weather parameters. Each of the three Member models include a

5   unique series of monthly binary variables that account for monthly

6   changes in peak demand that are not captured by the weather

7   variables. The Meade County model also includes an autoregressive

8   parameter to address first-order autocorrelation.

9

10

11   **Witness)**   John W. Hutts

12

BIG RIVERS ELECTRIC CORPORATION

**2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384**

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 47)**   *Refer to Appendix B, Section 2.2.3, page 5. Explain the Illinois*

2   *TRM and how it was used for the DSM modeling.*

3

4   **Response)** The Illinois Technical Reference Manual ("TRM") provides energy

5   efficiency measure savings calculations algorithms and inputs to support the

6   estimates of the State of Illinois' energy efficiency programs. This document provides

7   general information that can be used by planners in other states. The Illinois TRM

8   supported the DSM modeling by serving as the source of estimates of energy

9   efficiency measure savings, costs, and useful lives for a portion of the measures

10 included in the analysis.

11

12

13 **Witness)**   Warren E. Hirons

14

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 48)**   *Refer to Appendix B, Chapter 3. Provide the location of the*

2   *program potential mentioned in the first paragraph.*

3

4   **Response)**   The program potential is located in Chapter 6 of Appendix B.   The

5   sentence on page 11, in Chapter 3, of Appendix B that reads, *"Program potential is*

6   *discussed in Chapter 0"* is a typo. This statement should read, *"Program potential is*

7   *discussed in Chapter 6."*

8

9

10   **Witness)**   Russell L. Pogue

11

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOUCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's I
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 49)**   *Refer to Appendix B, Section 4.2.2. Explain why the lighting*

2   *impact does not decrease to zero for the nonresidential classes in the year*

3   *2021 as it does for the residential class.*

4

5   **Response)** The residential sector analysis accounts for the EISA backstop

6   provision and the effect of the U.S. Department of Energy's Final Rules on General

7   Service Lamps.[1] The non-residential sector analysis primarily addresses bulb and

8   fixture types that are not impacted by the EISA backstop provision. The analysis

9   assumes savings opportunities will continue to exist for these bulb and fixture types.

10   These assumptions should be revisited periodically to account for changes in

11   regulations and changes in the non-residential lighting market.

12

13   **Witness)**   Warren E. Hirons

14

---

[1] https://energy.gov/eere/buildings/downloads/two-gsl-final-rules

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOUCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 50)   *Refer to Appendix B, Section 5.8, page 37. Provide support for the*

2   *assumption that distributed generation will equal 350 kW for the commercial*

3   *class and 1000 kW for the industrial class.*

4

5   **Response)** Industrial class customers are defined in the load forecast as those

6   customers with connected load of 1,000 kVA or greater. Therefore, Big Rivers selected

7   a 1 MW distributed generation unit as representative of the industrial class. The

8   commercial class is composed of non-residential customers with load less than 1,000

9   kVA. Big Rivers selected a distributed generation unit size of 350 kW recognizing

10   that many commercial accounts have loads well below 350 kW but would not be likely

11   targets for a distributed generation demand response program. Rather, larger

12   commercial sites that could support generation of that size would be more likely

13   targets of such a program. Two size units were selected for initial screening of a

14   potential DR program. If a distributed generation program were pursued by Big

15   Rivers, a greater variety of loads could be considered when designing the program.

16

17

18   **Witness)**   Warren E. Hirons

19

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 51)**   *Refer to Appendix B, Section 5.9, page 41. Explain whether or not*

2   *Big Rivers has elected to pursue a formal demand response program since*

3   *this report was written.*

4

5   **Response)** Big Rivers has not elected to pursue a formal demand response program

6   since this report was written. Big Rivers will continue to evaluate opportunities for

7   demand response in the future.

8

9

10   **Witness)**   Russell L. Pogue

11

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 52)**   *Refer to Appendix B, Section 6.2, page 46, Table 6-8.*

2   *a.   For each DSM program, provide all modeling inputs used to*

3   *calculate the net present value benefits and costs and Total*

4   *Resource Cost ("TRC") scores.   This should be in an Excel*

5   *spreadsheet format will all formulas unprotected and all rows and*

6   *columns accessible.*

7   *b.   A TRC test score of 1.0 or above indicates that the benefits are*

8   *greater than the costs and the higher the score, the more beneficial*

9   *the program is. For each program whose TRC score is less than 1.0,*

10   *provide justification as to why Big Rivers should continue each*

11   *program.*

12

13   **Response)**

14   a.   Big Rives and GDS Associates have discovered an error in the original

15   modeling files. Updated model files, i.e., Excel files, are provided on the

16   CONFIDENTIAL electronic media accompanying these responses. This

17   error arose with the conversion of the avoided capacity costs, resulting in

18   higher Total Resource Cost ("TRC") test values.

19   b.   Big Rivers cannot justify programs which are not cost effective. For this

20   reason, on June 20, 2017, Big Rivers filed revised tariff sheets in Case No.

21   2017-00278[1] and, on July 6, 2018, Big Rivers filed revised tariff sheets in

---

[1] See *In the Matter of: Tariff Filing Of Big Rivers Electric Corporation To Revise Certain Demand-Side Management Programs*, Case No. 2017-00278

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
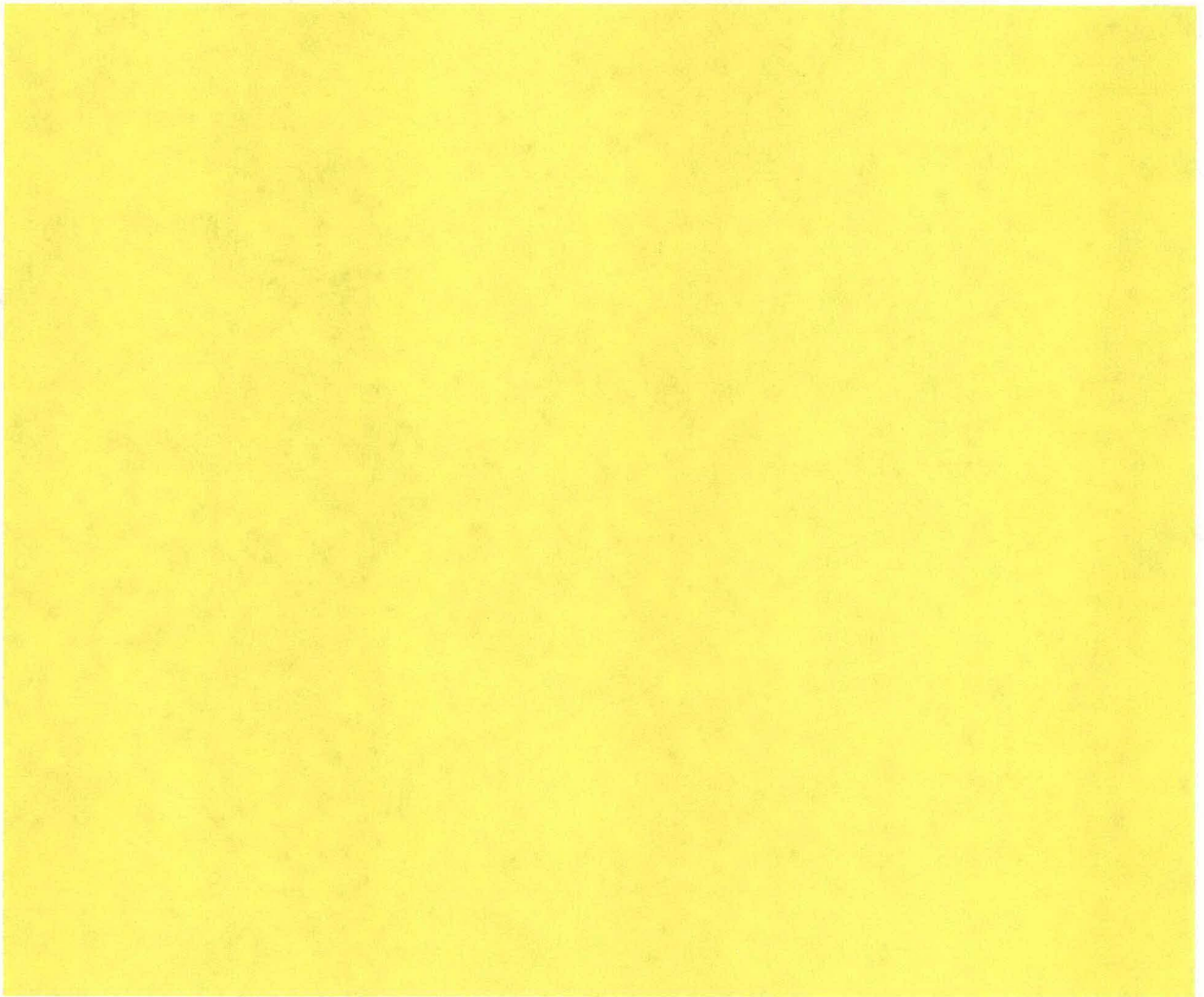dated June 22, 2018

July 20, 2018

1 Case No. 2018-00236.[2] In both cases, Big Rivers filed to withdraw those

2 DSM programs whose TRC test scores were less than 1.0. Because of the

3 correction of the conversion error mentioned in sub-part a. above, one DSM

4 program has dropped below the 1.0 TRC threshold, and that program will

5 be phased out.

6 　　　On December 21, 2017, the Commission issued its Order in Case No.

7 2017-00278. Case No. 2018-00236 is pending.

8

9

10 **Witness)** Russell L. Pogue

11

---

[2] See *In the Matter of: DSM Filing of Big Rivers Electric Corporation on behalf of Itself, Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation and Request to Establish a Regulatory Liability*, Case No. 2018-00236.

In the Matter of:

| 2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION |)) | Case No. 2017-00384 |

CONFIDENTIAL RESPONSE

to Item 52 of the Commission Staff's
First Request for Information
dated June 22, 2018
FILED: July 20, 2018

GDS DSM Model Overview etc. - Residential $1.0 Million

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

In the Matter of:

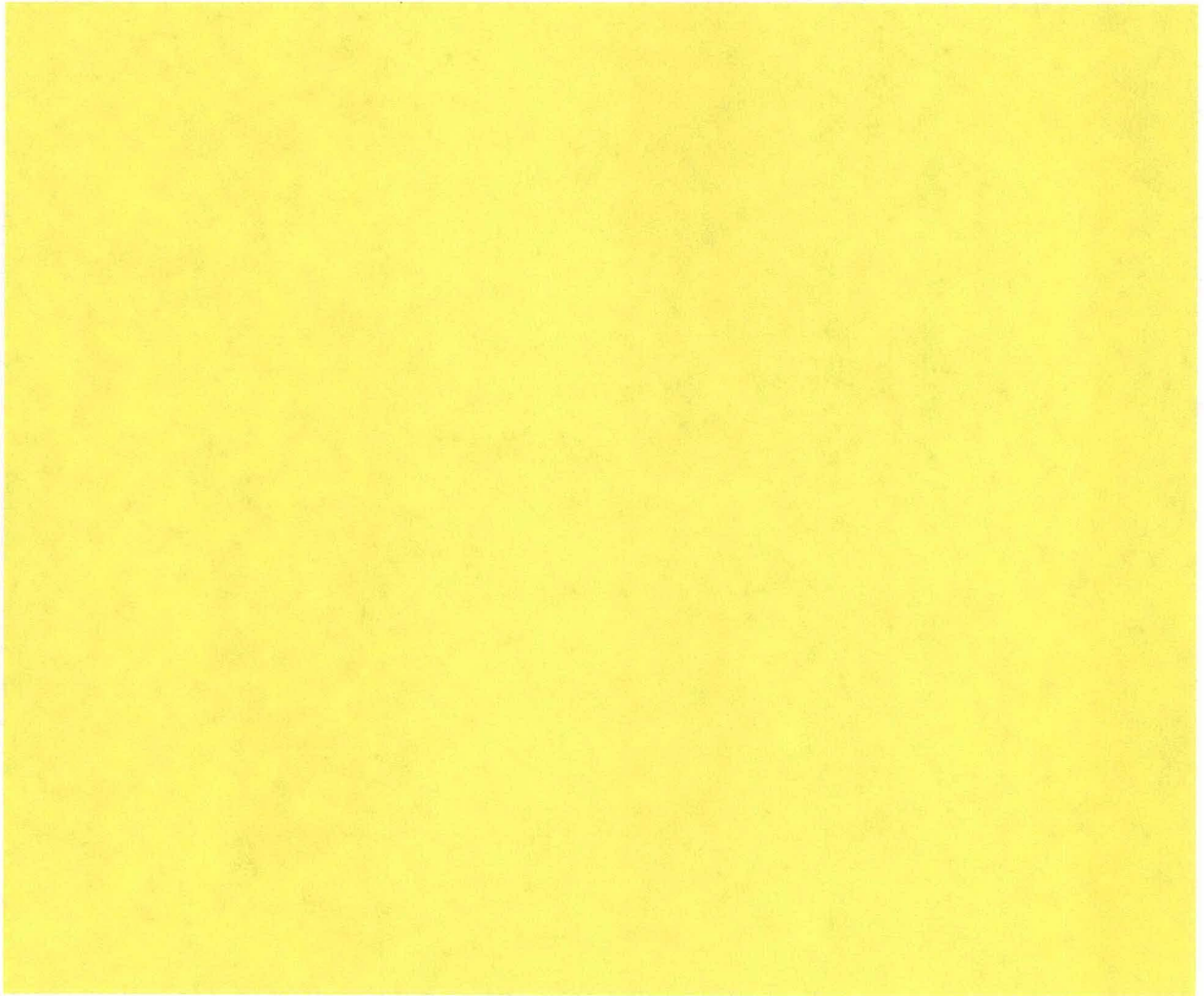2017 INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION)   Case No. 2017-00384

CONFIDENTIAL RESPONSE

to Item 52 of the Commission Staff's
First Request for Information
dated June 22, 2018
FILED: July 20, 2018

GDS DSM Model Overview etc. - Non-Residential $1.0 Million

<u>INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL
TREATMENT</u>

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 53)**   *Explain any other procedures that Big Rivers can adopt in*

2   *evaluating current and potential DSM programs.*

3

4   **Response)** Big Rivers is not aware of more effective methods or procedures for

5   evaluating its current and potential DSM programs.

6

7

8   **Witness)**   Russell L. Pogue

9

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   Item 54)   *Explain if there are any industrial DSM opportunities assumed*

2   *in the forecast.*

3

4   **Response)** There are no industrial DSM opportunities assumed in the DSM

5   potential study.

6

7

8   **Witness)**   Russell L. Pogue

9

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1 **Item 55)** *State whether Big Rivers has received any inquiries as to*

2 *available grants, subsidies, or low-interest loans for energy conservation or*

3 *energy efficiency from industrial customers that may help those customers*

4 *remain economically stable or market competitive.*

5

6 **Response)** Yes, Big Rivers has received inquiries from and provided assistance,

7 including evaluation and documentation, to industrial customers about improving

8 the energy efficiency in their facilities.

9

10

11 **Witness)**   Russell L. Pogue

12

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 56)**   *Explain whether there has been any change, internally or*

2   *externally, in the methods of evaluation, measurement and verification used*

3   *by Big Rivers for existing or proposed DSM programs. Identify the cost*

4   *associated with such changes, if they exist.*

5

6   **Response)** There has been no change, internally or externally, in the methods of

7   evaluation, measurement and verification used by Big Rivers for DSM programs.

8

9

10   **Witness)**   Russell L. Pogue

11

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to Commission Staff's
First Request for Information
dated June 22, 2018

July 20, 2018

1   **Item 57)**   *Refer to Appendix B, Appendix D, General Modeling*

2   *Assumptions, page D-2. Given the current excess capacity position of Big*

3   *Rivers, explain why the avoided costs are not zero.*

4

5   **Response)**   In the near-term, the avoided capacity costs should align with current

6   forward market prices. In the long-term, avoided cost projections should reflect a

7   long-term forecast of market prices. See section 4.3 and 4.4 of the attached document

8   entitled *"Understanding Cost-Effectiveness of Energy Efficiency Programs: Best*

9   *Practices, Technical Methods, and Emerging Issues for Policy-Makers."*

10

11

12   **Witness)**   Warren E. Hirons

13

Case No. 2017-00384
PSC 1-57 (WEH)(Att) - Understanding Cost-
Effectiveness of Energy Efficiency Programs:
Best Practices, Technical Methods, and Emerging
Issues for Policy-Makers
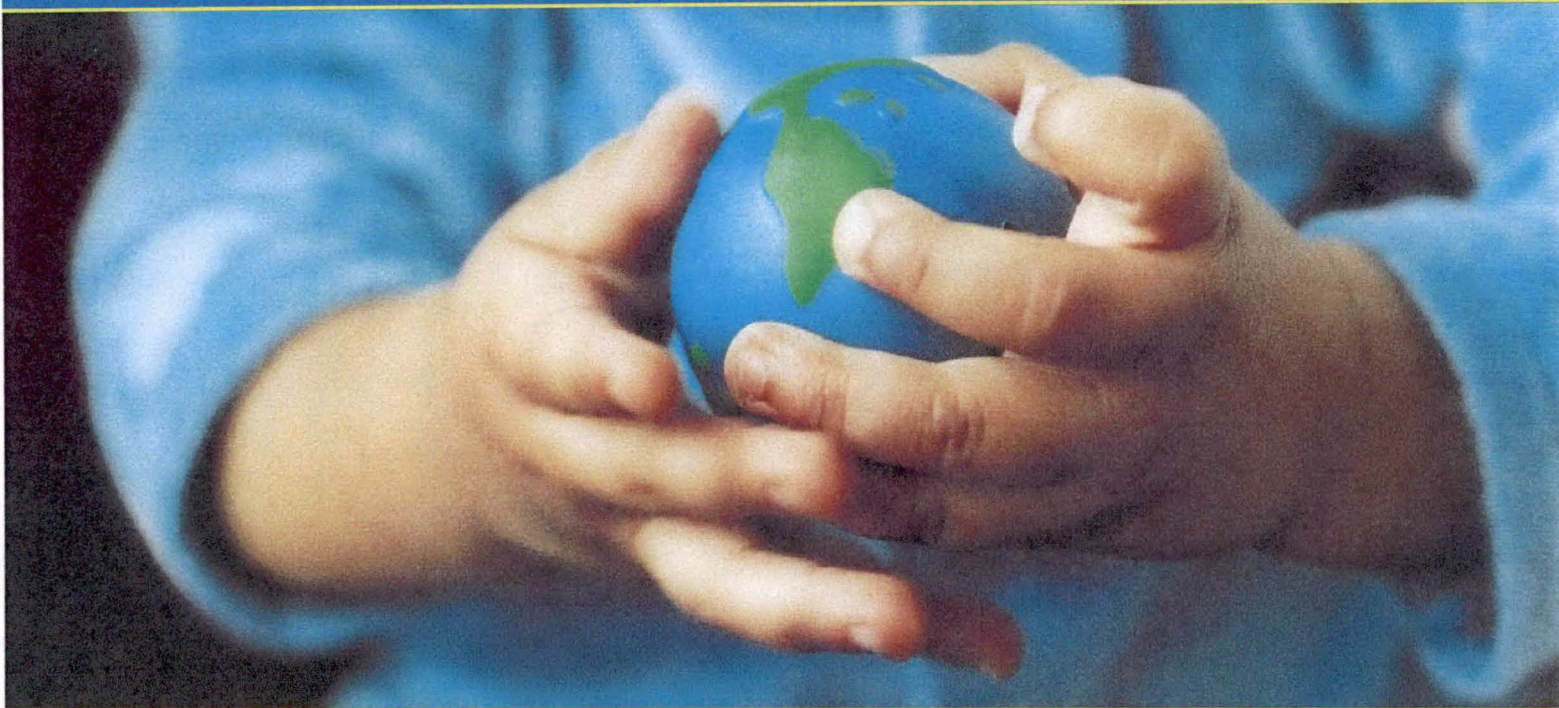
Understanding Cost-Effectiveness of Energy Efficiency Programs:

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

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2008

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

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.

If this document is referenced, it should be cited as:

National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* Energy and Environmental Economics, Inc. and Regulatory Assistance Project. <www.epa.gov/eeactionplan>

Table of Contents

List of Figures

List of Tables

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

Acknowledgements

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

- **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.

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) | $=$ | $\text{NPV} \sum \text{benefits}_a \text{ (dollars)} - \text{NPV} \sum \text{costs}_a \text{ (dollars)}$ |
| **Benefit-Cost Ratio** | Benefit-Cost Ratio$_a$ | $=$ | $\dfrac{\text{NPV} \sum \text{benefits}_a \text{ (dollars)}}{\text{NPV} \sum \text{costs}_a \text{ (dollars)}}$ |

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.

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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
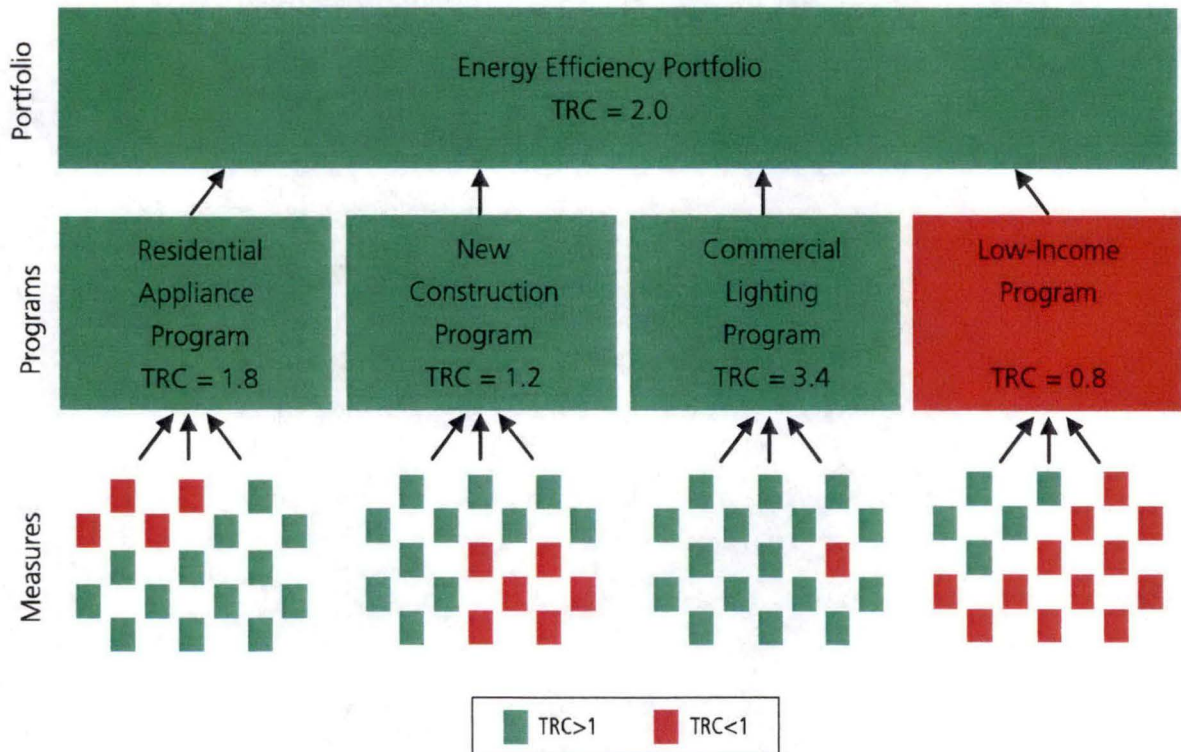
Applying cost-effectiveness tests at the measure level is the most restrictive. With this approach, the analyst or policy-maker is explicitly or implicitly emphasizing the cost-effectiveness rather than the total energy savings of the efficiency portfolio. In contrast, applying cost-effectiveness tests 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

Understanding Cost-Effectiveness of Energy Efficiency Programs

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
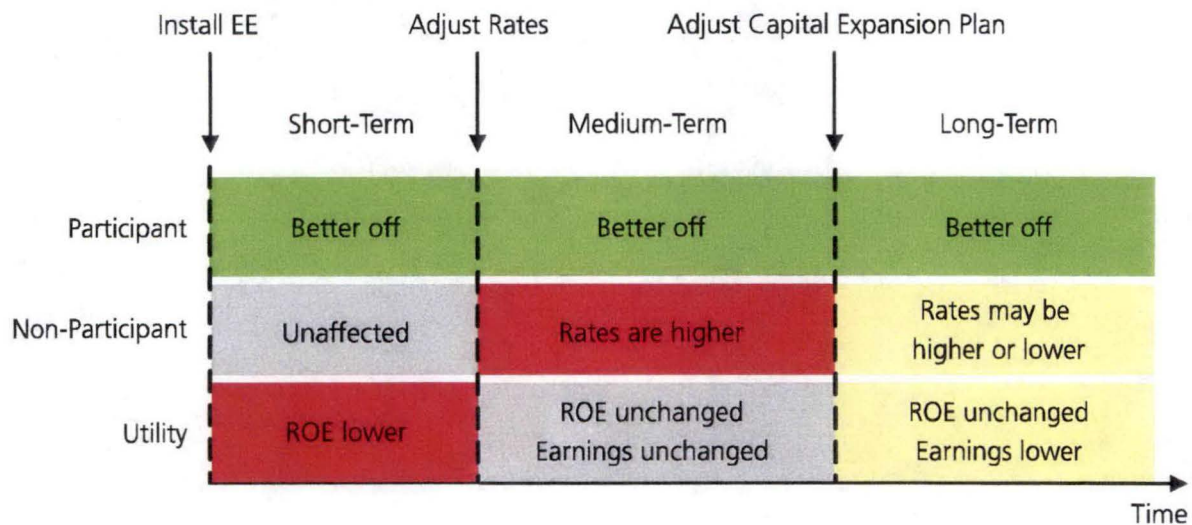
From a participant perspective, because the PCT is above 1.0, the participant is better off once an investment in energy efficiency is made, as the utility bill is lower than it would have been throughout the time horizon. In the short term, the non-participant is indifferent since rates have not been 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).

Understanding Cost-Effectiveness of Energy Efficiency Programs

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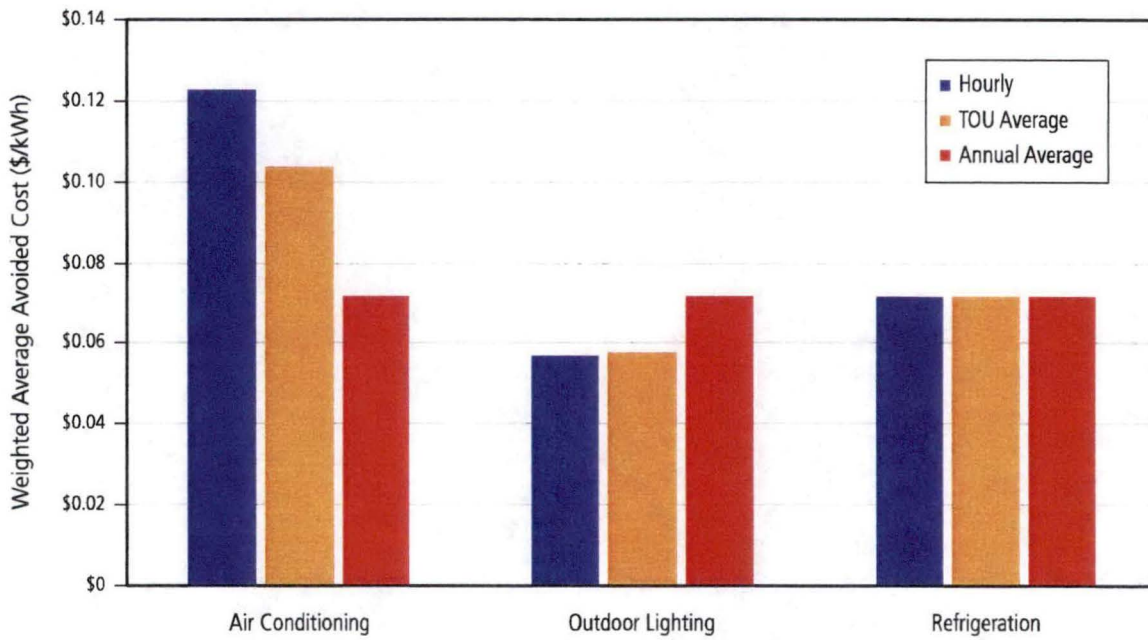
Source: California Proceeding on Avoided Costs of Energy Efficiency; R.04-04-025.

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
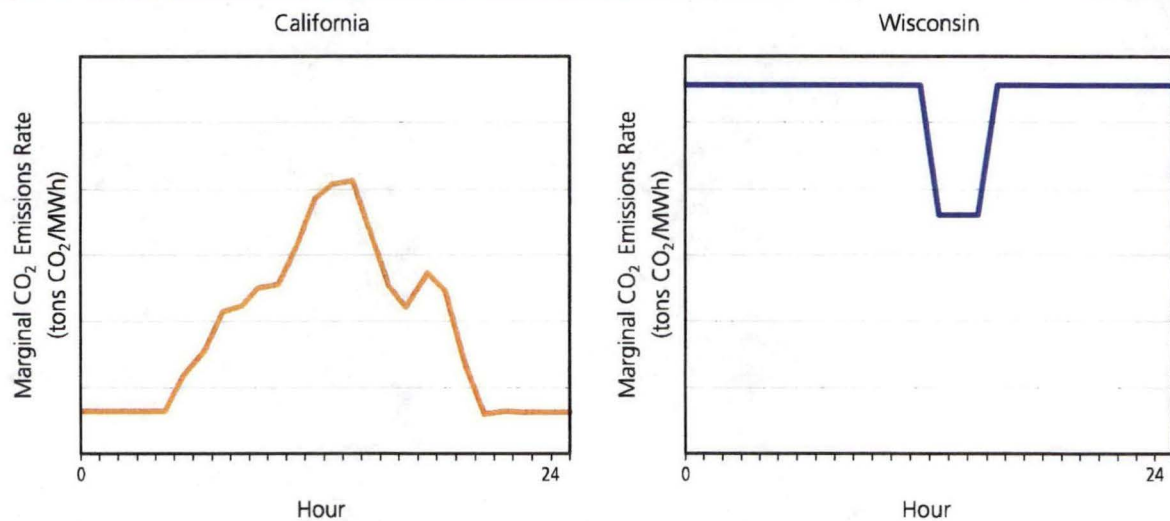
Source: Erickson et al. (2004).

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
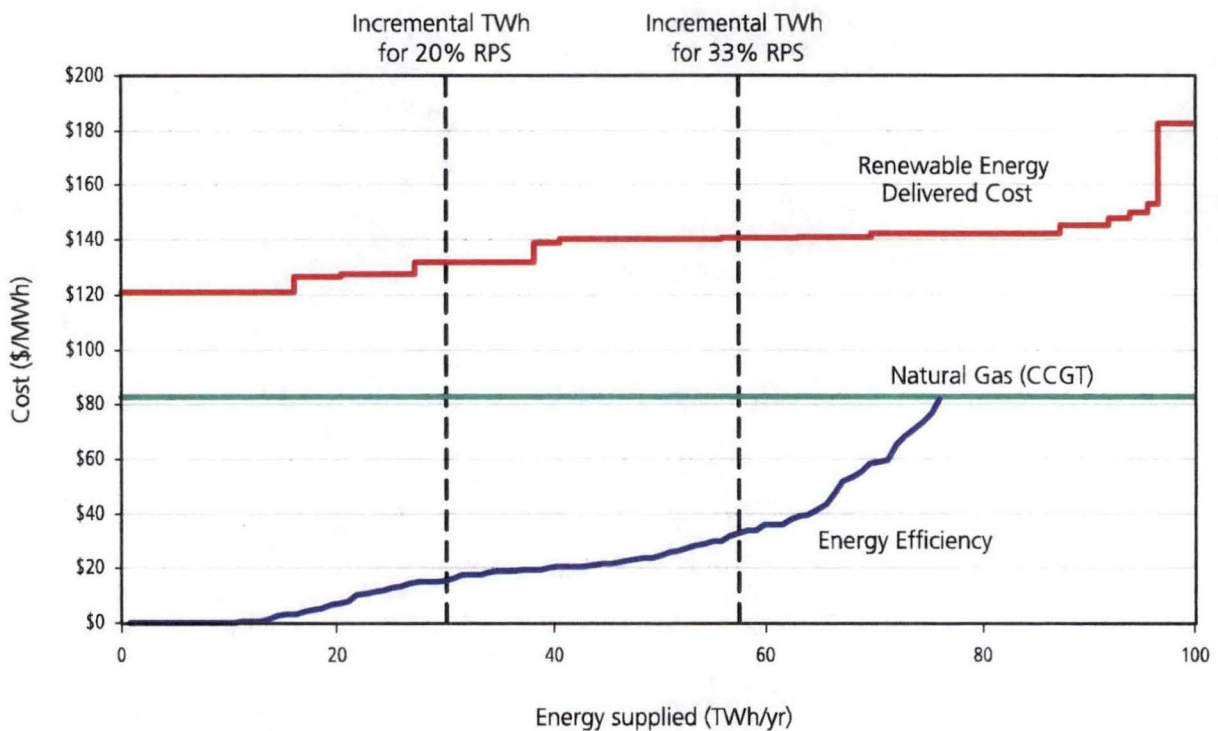
Source: Mahone et al. (2008).

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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.

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.

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.

> **"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.

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

Co-Chairs

Marsha Smith
Commissioner, Idaho Public
Utilities Commission
President, National Association
of Regulatory Utility
Commissioners

James E. Rogers
Chairman, President, and
C.E.O.
Duke Energy

Leadership Group

Barry Abramson
Senior Vice President
Servidyne Systems, LLC

Tracy Babbidge
Director, Air Planning
Connecticut Department of
Environmental Protection

Angela Beehler
Senior Director, Energy
Regulation/Legislation
Wal-Mart Stores, Inc.

Sheila Boeckman
Manager of Business
Operations and Development
Waverly Light and Power

Bruce Braine
Vice President, Strategic Policy
Analysis
American Electric Power

Jeff Burks
Director of Environmental
Sustainability
PNM Resources

Kateri Callahan
President
Alliance to Save Energy

Jorge Carrasco
Superintendent
Seattle City Light

Lonnie Carter
President and C.E.O.
Santee Cooper

Sheryl Carter
Co-Director, Energy Program
Natural Resources Defense
Council

Gary Connett
Director of Environmental
Stewardship and Member
Services
Great River Energy

Larry Downes
Chairman and C.E.O.
New Jersey Natural Gas (New
Jersey Resources Corporation)

Roger Duncan
Deputy General Manager,
Distributed Energy Services
Austin Energy

Angelo Esposito
Senior Vice President, Energy
Services and Technology
New York Power Authority

Jeanne Fox
President
New Jersey Board of Public
Utilities

Philip Giudice
Commissioner
Massachusetts Division of
Energy Resources

Dian Grueneich
Commissioner
California Public Utilities
Commission

Blair Hamilton
Policy Director
Vermont Energy Investment
Corporation

Maureen Harris
Commissioner
New York State Public Service
Commission

Mary Healey
Consumer Counsel for the State
of Connecticut
Connecticut Consumer Counsel

Joe Hoagland
Vice President, Energy
Efficiency and Demand
Response
Tennessee Valley Authority

Sandy Hochstetter
Vice President, Strategic Affairs
Arkansas Electric Cooperative
Corporation

Helen Howes
Vice President, Environment,
Health and Safety
Exelon

Mary Kenkel
Consultant, Alliance One
Duke Energy

Ruth Kiselewich
Director, Conservation
Programs
Baltimore Gas and Electric
Company

Martin Kushler
Director, Utilities Program
American Council for an
Energy-Efficient Economy

Rick Leuthauser
Manager of Energy Efficiency
MidAmerican Energy Company

Harris McDowell
Senator
Delaware General Assembly

Ed Melendreras
Vice President, Sales and
Marketing
Entergy Corporation

Janine Migden-Ostrander
Consumers' Counsel
Office of the Ohio Consumers'
Counsel

Michael Moehn
Vice President, Corporate
Planning
Ameren Services

Fred Moore
Director, Manufacturing and
Technology, Energy
The Dow Chemical Company

Richard Morgan
Commissioner
District of Columbia Public
Service Commission

Clay Nesler
Vice President, Global Energy
and Sustainability
Johnson Controls, Inc.

Brock Nicholson
Deputy Director, Division of Air
Quality
North Carolina Department of
Environment and Natural
Resources

Jed Nosal
Chief, Office of Ratepayer
Advocacy
Massachusetts Office of
Attorney General Martha
Coakley

Pat Oshie
Commissioner
Washington Utilities and
Transportation Commission

John Perkins
Consumer Advocate
Iowa Office of Consumer
Advocate

Douglas Petitt
Vice President, Government
Affairs
Vectren Corporation

Phyllis Reha
Commissioner
Minnesota Public Utilities
Commission

Roland Risser
Director, Customer Energy
Efficiency
Pacific Gas and Electric

Gene Rodrigues
Director, Energy Efficiency
Southern California Edison

Wayne Rosa
Energy and Maintenance
Manager
Food Lion, LLC

Art Rosenfeld
Commissioner
California Energy Commission

Jan Schori
General Manager
Sacramento Municipal Utility
District

Ted Schultz
Vice President, Energy
Efficiency
Duke Energy

Larry Shirley
Division Director
North Carolina Energy Office

Paul Sotkiewicz
Senior Economist, Market
Services Division
PJM Interconnection

Jim Spiers
Senior Manager, Planning,
Rates, and Member Services
Tristate Generation and
Transmission Association, Inc.

Susan Story
President and C.E.O.
Gulf Power Company (Southern
Company)

Tim Stout
Vice President, Energy
Efficiency
National Grid

Deb Sundin
Director, Business Product
Marketing
Xcel Energy

Paul Suskie
Chairman
Arkansas Public Service
Commission

Dub Taylor
Director
Texas State Energy
Conservation Office

David Van Holde
Energy Manager, Department of
Natural Resources and Parks
King County, Washington

Brenna Walraven
Managing Director, National
Property Management
USAA Realty Company

J. Mack Wathen
Vice President, Regulatory
Affairs
Pepco Holdings, Inc.

Mike Weedall
Vice President, Energy
Efficiency
Bonneville Power Administration

Michael Wehling
Strategic Planning and
Research
Puget Sound Energy

Henry Yoshimura
Manager, Demand Response
ISO New England, Inc.

Dan Zaweski
Assistant Vice President of
Energy Efficiency and
Distributed Generation
Long Island Power Authority

Observers

Rex Boynton
President
North American Technician
Excellence

James W. (Jay) Brew
Counsel
Steel Manufacturers Association

Roger Cooper
Executive Vice President, Policy
and Planning
American Gas Association

Mark Crisson
President and C.E.O.
American Public Power
Association

Dan Delurey
Executive Director
Demand Response
Coordinating Committee

Reid Detchon
Executive Director
Energy Future Coalition

Ron Edelstein
Director, Regulatory and
Government Relations
Gas Technology Institute

Sue Gander
Director, Environment, Energy,
and Natural Resources Division
National Governors
Association—Center for Best
Practices

Jeff Genzer
General Counsel
National Association of State
Energy Officials

Donald Gilligan
President
National Association of Energy
Service Companies

Chuck Gray
Executive Director
National Association of
Regulatory Utility
Commissioners

Steve Hauser
President
GridWise Alliance

William Hederman
Member, IEEE-USA Energy
Policy Committee
Institute of Electrical and
Electronics Engineers

Marc Hoffman
Executive Director
Consortium for Energy
Efficiency

John Holt
Senior Manager of Generation
and Fuel
National Rural Electric
Cooperative Association

Eric Hsieh
Manager of Government
Relations
National Electrical
Manufacturers Association

Lisa Jacobson
Executive Director
Business Council for
Sustainable Energy

Kate Marks
Energy Program Manager
National Conference of State
Legislatures

Meg Matt
President and C.E.O.
Association of Energy Services
Professionals

Joseph Mattingly
Vice President, Secretary and
General Counsel
Gas Appliance Manufacturers
Association

Kenneth Mentzer
President and C.E.O.
North American Insulation
Manufacturers Association

Ellen Petrill
Director, Public/Private
Partnerships
Electric Power Research
Institute

Steven Schiller
Board Director
Efficiency Valuation
Organization

Jerry Schwartz
Senior Director
American Forest and Paper
Association

Andrew Spahn
Executive Director
National Council on Electricity
Policy

Rick Tempchin
Director, Retail Distribution
Policy
Edison Electric Institute

Mark Wolfe
Executive Director
Energy Programs Consortium

Lisa Wood
Executive Director
Institute for Electric Efficiency

Facilitators

U.S. Department of Energy

U.S. Environmental Protection
Agency

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 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>.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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.

Understanding Cost-Effectiveness of Energy Efficiency Programs

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

Test	Cost	Benefits
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 D: References

Erickson, J., B. Ward, and J. Mapp (2004). *Peak Demand Reduction vs. Emissions Savings: When Does It Pay to Chase Emissions?* ACEEE Summer Study paper.

Golove, W.H., and J.H. Eto (1996). *Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy Efficiency.* Lawrence Berkeley National Laboratory LBL-38059.

Mahone, A., J. Moore, J. Williams, and C.K. Woo (2008). *Energy Efficiency's Impact on California's Renewable Energy Development.* 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 17–22, 2008, Pacific Grove, CA.

National Action Plan for Energy Efficiency (2006). *The National Action Plan for Energy Efficiency.* <http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html>

National Action Plan for Energy Efficiency (2007a). *Aligning Utility Incentives with Energy Efficiency Investment.* Prepared by Val R. Jensen, ICF International. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2007b). *Guide to Resource Planning with Energy Efficiency.* Prepared by Snuller Price et al., Energy and Environmental Economics, Inc. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2007c). *Model Energy Efficiency Program Impact Evaluation Guide.* Prepared by Steven R. Schiller, Schiller Consulting, Inc. <http://www.epa.gov/eeactionplan>

National Action Plan for Energy Efficiency (2008). *National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change.* <http://www.epa.gov/eeactionplan>

Schleich, J., and E. Gruber (2008). Beyond case studies: Barriers to energy efficiency in commerce and the services sector. *Energy Economics* 30: 449-464. <http://eetd.lbl.gov/ea/emp/reports/38059.pdf>